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COVID-19 IMPACTS ON 2020 ERCOT ELECTRICITY MARKET

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Dear Reader,

For the week ending April 18, 2020, U.S. electricity output was down over the same week in 2019 in every region of the United States. Since the COVID pandemic hit the United States, millions of Americans have lost their jobs and filed for unemployment, some estimates putting unemployment rates as high as 25 percent. Grade schools and universities are closed across the country. Many businesses have closed their doors for good. At the same time, in China, where shutdowns triggered dramatic reductions in manufacturing, the sector is seeing "modest improvement" in its purchase manager surveys, an indicator of manufacturing output, according to the International Monetary Fund. No one knows how long U.S. shutdowns and closures will continue or how quickly economies will bounce back.

It is in the face of all this uncertainty that we at LCG struggle to make sense of what to expect in Texas over the remainder of 2020 and beyond. We offered our "business-as-usual" projections for the year in our 2020 ERCOT Outlook, which examines the Texas market as if we were not experiencing a global pandemic. And now we would like to offer this addendum that incorporates what little real data we have from a few weeks into this pandemic.

For electricity, the shifts have not been catastrophic. However, in ERCOT electricity generation is noticeably down, as it is across the country. This downward trend was more profound in parts of California, down 13 percent in some areas, and the Central Industrial states – Michigan, Indiana, Illinois, Ohio, and parts of Pennsylvania - down by nearly 7 percent, according to the Edison Electric Institute.

We are monitoring ERCOT closely for any changes. Generation and transmission projects that we expected to come online may be mothballed, fuel prices will change, demand may shift both geographically and temporally, peak demand hours may move or decline in magnitude, and many other unforeseen changes are likely, so this addendum is only a first attempt at modeling, based on what little data we have available.

We do have the ability to build new models with a host of new detailed assumptions, adjusting fuel prices, removing or adding transmission and generation, or building new demand curves on a bus-by-bus level. We will be exploring how to continue to model ERCOT as accurately as possible as new data becomes available. For now, we offer this first-pass re-calibration of our normal ERCOT Outlook for 2020, using our UPLAN Network Power Model (NPM) and PLATO-ERCOT data model.

We welcome any feedback on what stakeholders may be experiencing or what expected changes to ERCOT we might consider in maintaining and adjusting our databases and scenarios over this uncertain year. Stay safe.

Sincerely yours,

Rajat Deb
LCG Consulting

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1. INTRODUCTION

1.1 BACKGROUND

The COVID-19 pandemic is having a profound impact on daily life and the economy, from affecting which businesses are allowed to operate, to influencing international oil prices. States and major cities in the US are instituting quarantines, along with shelter-in-place directives, to contain the spread of COVID-19. Power markets will likely deviate from their business-as-usual scenario as a result of decline in power demand and fuel prices.

ERCOT began monitoring load impacts directly related to COVID-19 during the week of March 8, and is providing updates on load changes from April. We at LCG is closely watching the impacts of COVID-19 on power markets. As the economic repercussions of shutdowns are evolving each day, we can only present information based on the last few weeks, which are unlikely to reflect exactly what will happen over the summer. Whether we can expect a summer close to normal or one that changes because of large shifts in the workforce, we are unable to confirm. Generation and transmission projects that we projected to come online may be mothballed, fuel prices will change, and many other unforeseen shifts are likely, so this addendum is only a first pass at modeling, based on what little data we have available.

We do have the ability to build new models with a host of new detailed assumptions, from fuel prices to ramp rates and new demand curves on a bus-by-bus level, and we will be exploring how to continue to model ERCOT as accurately as possible as new data becomes available. This addendum is modeled using our UPLAN Network Power Model (NPM) and PLATO-ERCOT data model.

1.2 SUMMARY OF CHANGES

From a month of observation by ERCOT, little impact has been observed on the daily peaks. However, load is consistently lower during the early morning hours between 6 a.m. and 10 a.m., a reduction of 6 to 10 percent from prediction under BAU[1] Outlook published by LCG. Two weeks of data also show that the weekly energy use has decreased by 2 percent.[2] Based on these observations, for April through June, load between 6 and 10 a.m. decreases by 10 percent, and monthly energy is decreased by 2 percent.

Natural gas prices are also affected. Sources anticipate a drop in natural gas prices in the coming months. In the simulation, natural gas price decreases by 10 percent from April to June to reflect the impact.

[1] BAU (Business-as-Usual) scenario: See 2020 ERCOT Electricity Market Outlook http://www.energyonline.com/Reports/Files/LCG.ERCOT.2020_Brief.pdf

2 ERCOT, COVID-19 Load Impact Analysis, http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_FINAL.pdf

1.3 SUMMARY OF FINDINGS

1. Coal generation drops sharply from April to June due to a compound effect of load shape change and natural gas prices drop. Generation from other fuels also drops in general due to lower energy demand.
2. Prices are lower in all load zones and hubs. The biggest reduction is observed in the west load zone, dropping by as much as 50% in April. Nodal prices in the west also see declining prices.
3. Congestion conditions change due to COVID impacts. Notably Panhandle Interface becomes one of the top congestion.

2. SIMULATION RESULTS

2.1 GENERATION

Generation from April to June that are adjusted under COVID scenario is shown in Table 1, BAU scenario generation is shown in Table 2.

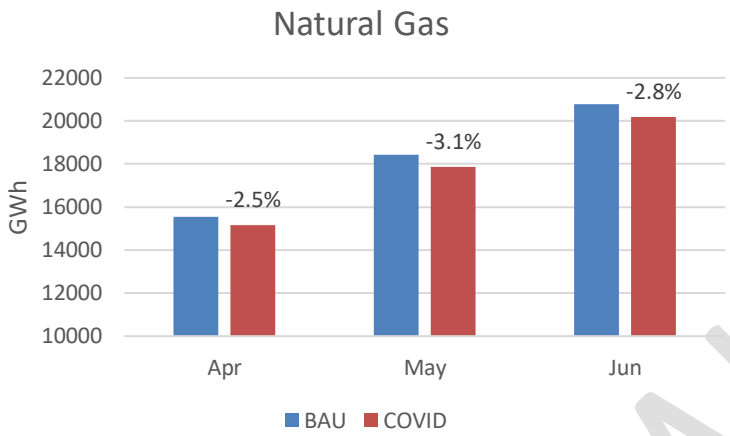
Table 1 Generation from April to June under COVID scenario (GWh)

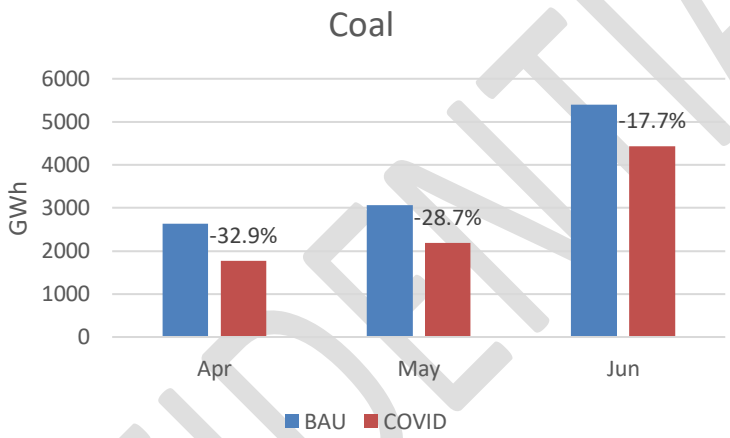
	Other	Nuclear	Wind	Coal	Natural Gas
Apr	1117	2575	9159	1770	15160
May	1384	3149	10007	2180	17854
Jun	1581	3605	8603	4439	20184

Table 2 Generation from April to June under BAU scenario (GWh)

	Other	Nuclear	Wind	Coal	Natural Gas
Apr	1136	2579	9178	2636	15543
May	1382	3150	10001	3058	18418
Jun	1580	3605	8596	5394	20764

Decline in energy demand and natural gas price lead to less generation, especially in coal generation. Coal generation decreases by 33%, 29%, 18% from April to June compared to BAU scenario, partly because of lower natural gas cost. Natural gas generation also sees a 3% decrease, likely due to the decline in energy demand. Changes in generation are shown in Figure 1.





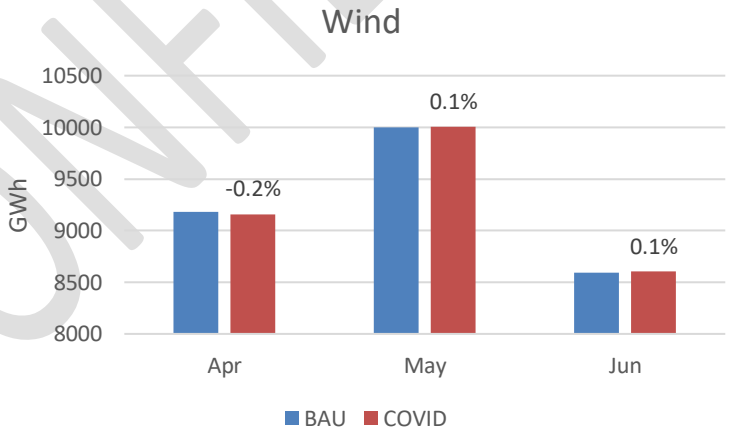


Figure 1 Change in monthly generation due to COVID impact

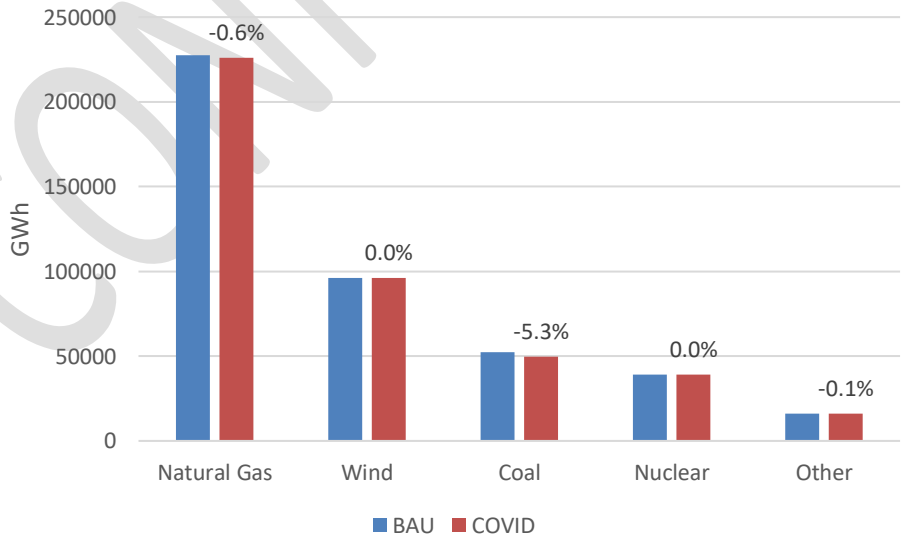


Figure 2 Decline in annual generation due to COVID impact

Spreading the impacts over a year, as shown in Figure 2, coal generation decreases by 5%, natural gas generation decreases by 0.6%, and the total generation as a result decreases by 1%.

2.2 CONGESTION

Ranked by annual congestion rent, some lines stay as the top congested lines, while others are alleviated.

Table 3 Congestion under COVID scenario (ranked by congestion rent)

Line Name	Voltage (kV)	Zone
DOLLARHIDE - NO TREES SWITCH	138	WEST
AROYA SWITCH - YUCCA DRIVE SWITCH	138	WEST
SOUTH TEXAS PROJECT - WA PARISH	345	SOUTH/ HOUSTON
NORTH - HOUSTON IMPORT INTERFACE		NORTH
KENDALL - BERGHEIM	345	LCRA
BURNS SUB - RIO HONDO	138	SOUTH
DOLLARHIDE - AMOCO THREE BAR TAP – ANDREWS COUNTY	138	WEST
WEST TNP - TI TNP	138	NORTH
KNAPP - SCURRY CHEVRON	138	WEST
PANHANDLE INTERFACE		WEST TO NORTH
FALFURRIAS TO PREMONT	69	SOUTH

Table 4 Congestion under BAU scenario (ranked by congestion rent)

Line Name	Voltage (kV)	Zone
DOLLARHIDE - NO TREES SWITCH	138	WEST
AROYA SWITCH - YUCCA DRIVE SWITCH	138	WEST
SOUTH TEXAS PROJECT - WA PARISH	345	SOUTH/ HOUSTON
NORTH - HOUSTON IMPORT INTERFACE		NORTH
KENDALL - BERGHEIM	345	LCRA
DOLLARHIDE - AMOCO THREE BAR TAP – ANDREWS COUNTY	138	WEST
BURNS SUB - RIO HONDO	138	SOUTH
WEST TNP - TI TNP	138	NORTH
NORTH EDINBERG 138/69 kV TRANSFORMER	138	SOUTH
KNAPP - SCURRY CHEVRON	138	WEST

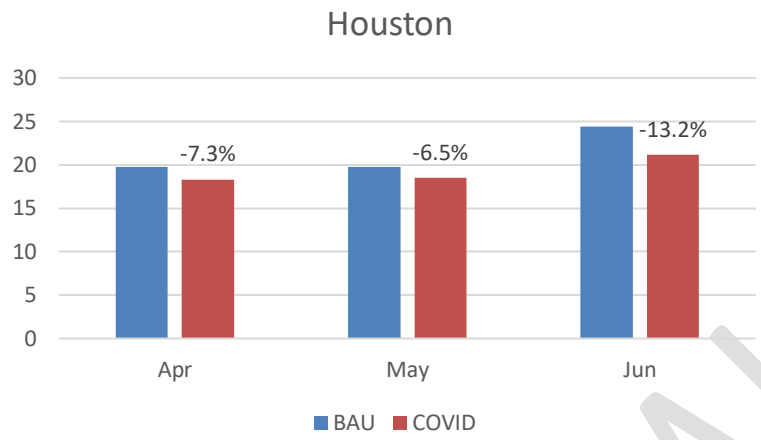
2.3 LOAD ZONE PRICES

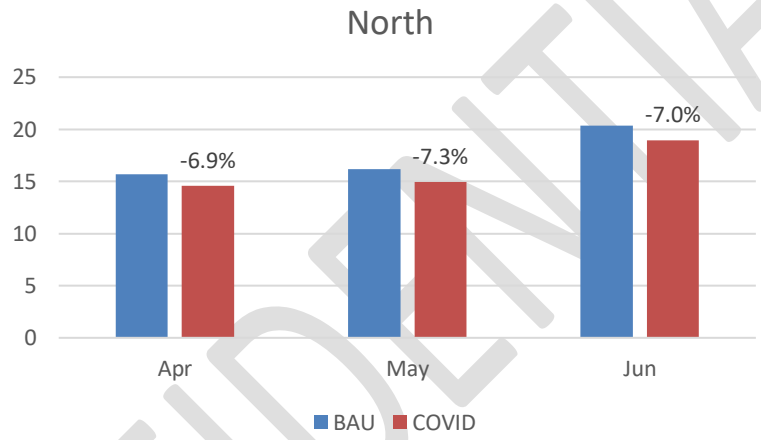
New load zone prices as a result of COVID impacts are shown in Table 5.

Table 5 Load zone prices from April to June under COVID scenario ($/MWh)

Month	LZ_HOUSTON	LZ_NORTH	LZ_SOUTH	LZ_WEST
Apr	18.30	14.59	24.76	13.24
May	18.50	14.98	16.77	13.93
Jun	21.15	18.93	21.59	15.84

Peak and off-peak load zone prices all drop due to the decline in energy demand and fuel cost. A sharp drop is observed for the West load zone. The West load zone prices drop by 52%, 16%, 21% from April to June respectively due to COVID impacts. The impacts of COVID on the price can still be felt when viewing the price averaged over a year. Houston, North, and South load zone sees 1-3% drop in price, whereas West load zone price drops by 5%. The comparison of the zonal prices between the BAU case and the COVID case is shown in Figure 3.





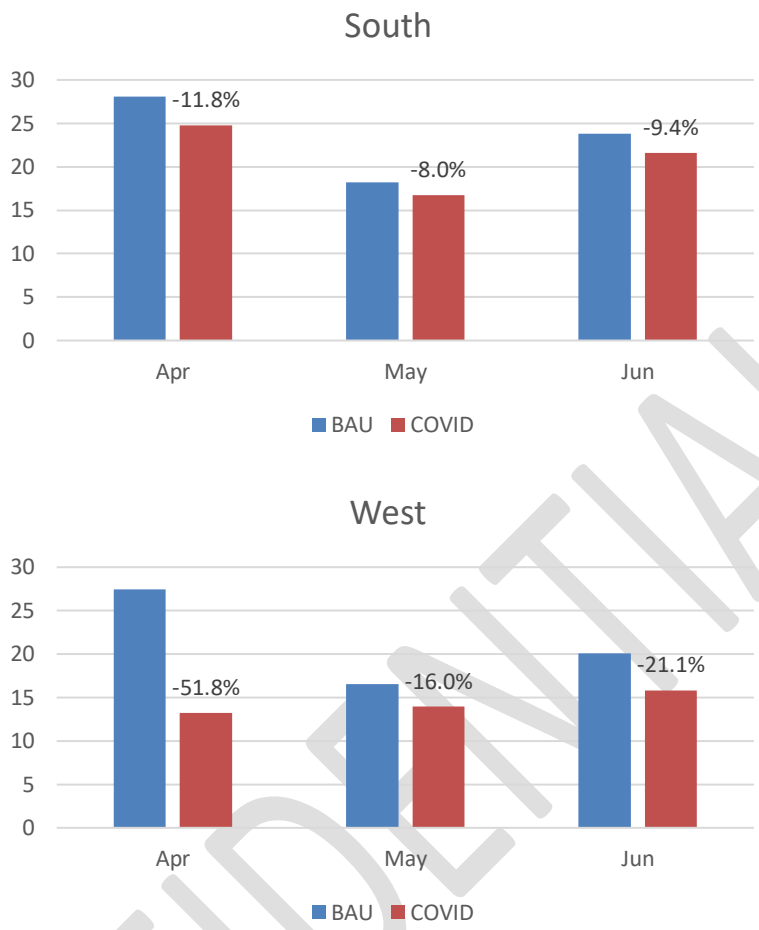


Figure 3 Decline in load zone price due to COVID impact

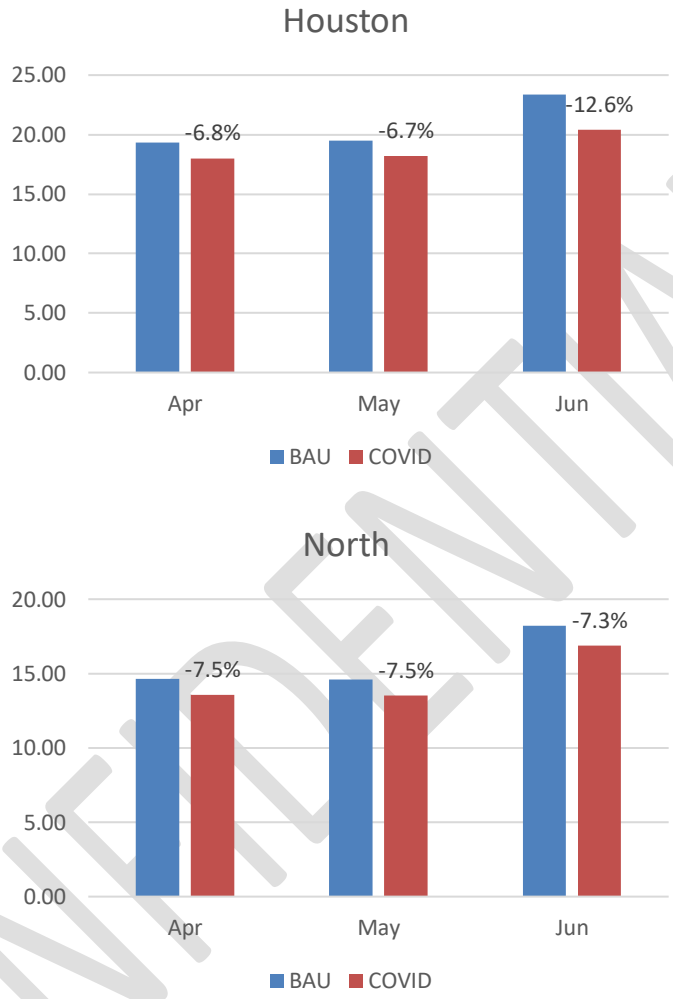
2.4 HUB PRICES

New hub prices resulted from COVID impacts are shown in Table 6.

Table 6 Hub prices from April to June under COVID scenario ($/MWh)

	HB_HOUSTON	HB_NORTH	HB_SOUTH	HB_WEST
Apr	17.99	13.56	16.95	7.64
May	18.18	13.51	16.03	11.52
Jun	20.41	16.87	18.00	14.91

Hub prices from April to June in each hub decrease about 7-10%, with the biggest drop being 13% at the Houston hub in April. Viewing the impacts over a year, hub prices decrease about 1-2%. The comparison of the hub prices between the BAU case and the COVID case is shown in Figure 4.



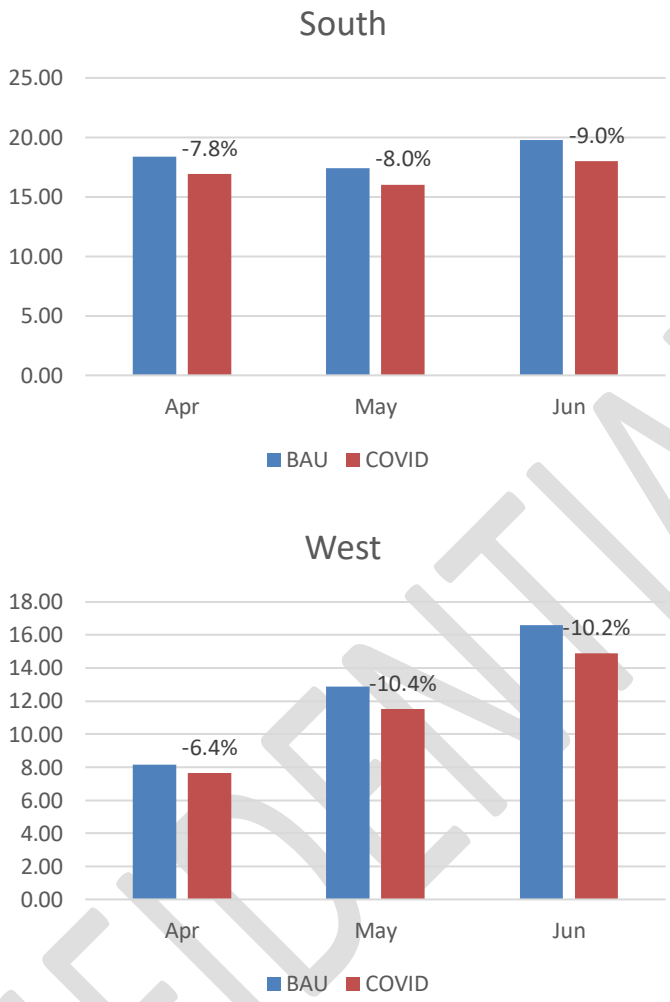


Figure 4 Decline in hub price due to COVID impact

2.5 NODAL PRICES

Comparing the annual nodal price between BAU and COVID scenarios, the nodal prices in the west zone decline in general, which can be observed from the map shown in Figure 5 and Figure 6.

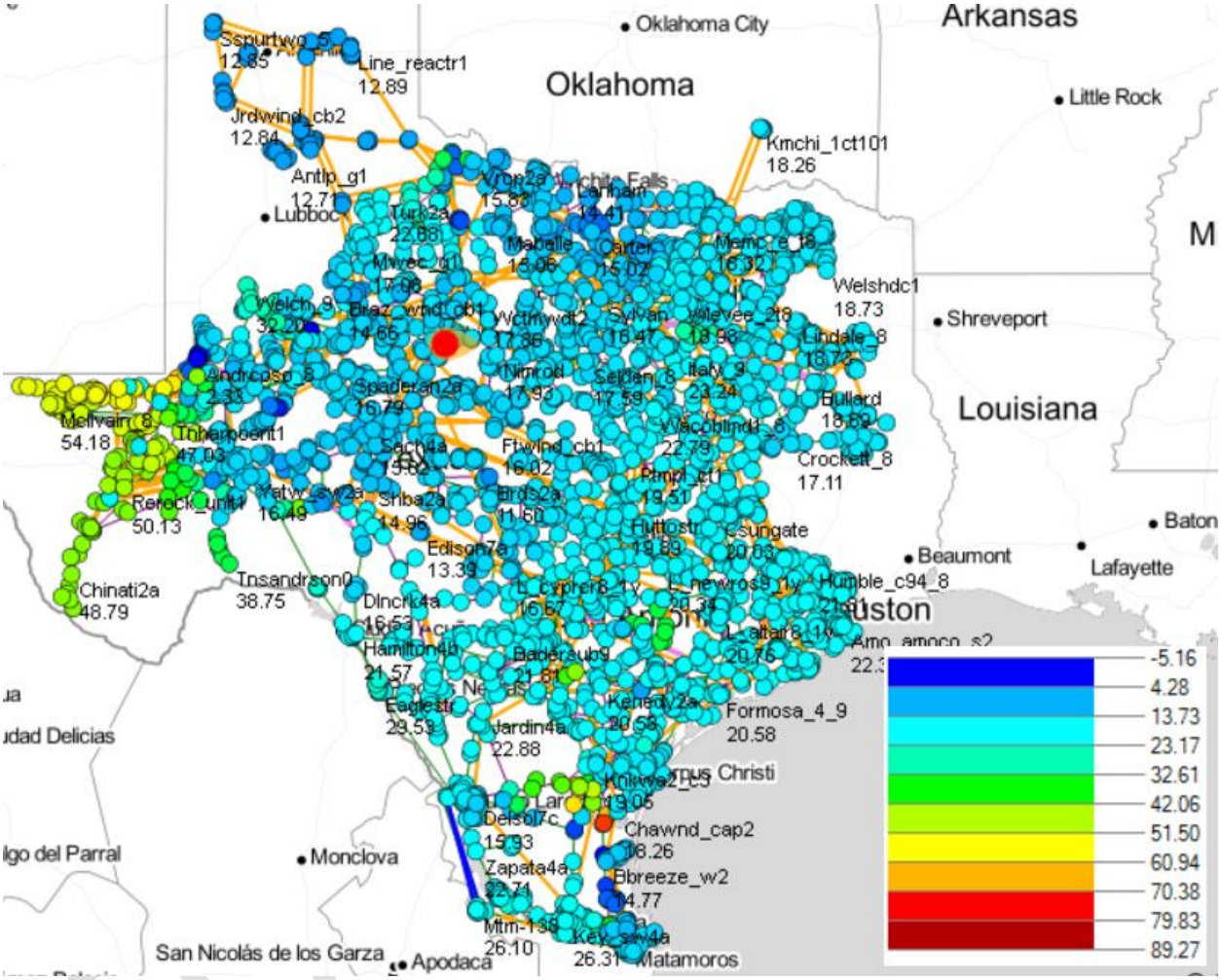


Figure 5 Annual nodal prices under COVID scenario ($/MWh)

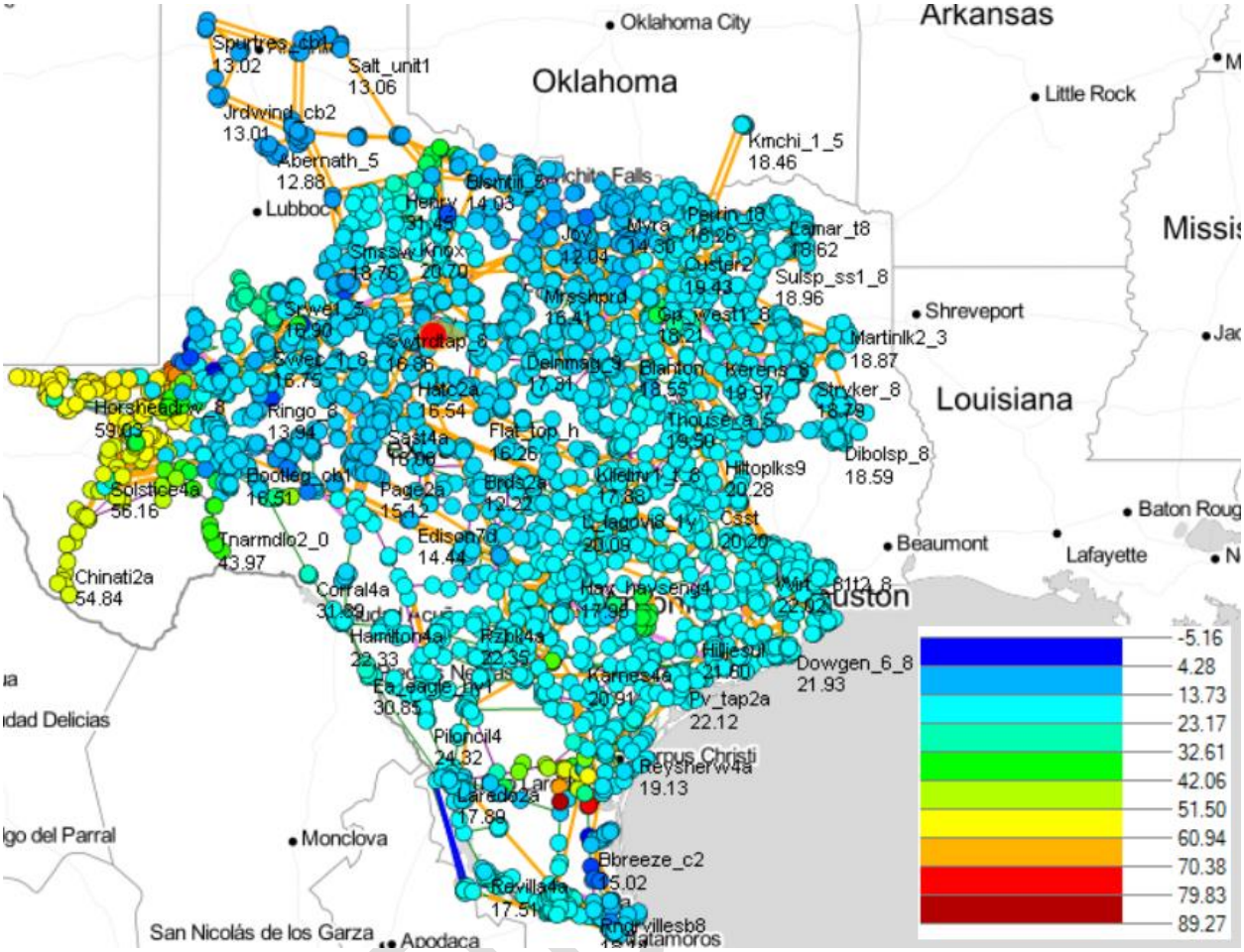


Figure 6 Annual nodal prices under BAU scenario ($/MWh)

In the COVID case the average annual nodal prices are lower than the BAU case, which is primarily due to the decline in the fuel prices and energy consumption. Note that the BAU case is for the entire 2020 whereas in the COVID case the simulation was performed for 2020 with COVID assumptions applied to April, May and June.