MID-C WHOLESALE PRICE FORECAST ATTACHMENT

1 INTRODUCTION

The 2015 Mid-C wholesale price forecast supersedes all previous forecasts and should be used in analyses requiring a long term forecast of wholesale electricity prices under average market conditions. The following items have a significant impact on forward prices and play key roles when performing fundamental sensitivities:

- Total capacity by fuel type. The assumptions of new generation and retired generation can increase or decrease prices. Industrial Info Resources was the provider of retirement dates and dates of new build outs.
- Winter snowpack levels. A wetter water year can decrease Q2 and Q3 Mid-C prices whereas a dry year can increase them. The base case price forecast assumes average water years.
- Load growth and seasonal weather patterns. Increased load growth and/or destruction assumptions will affect how high or low the marginal unit will be in the Mid-C supply stack. Coupled with an unusually cold winter in the Pacific Northwest or an extremely hot summer in the Southwest, prices around the entire WECC can become extremely volatile.
- Natural gas based generation creates the marginal price for electricity after all the renewable energy has been dispatched into the market. Gas fired generation is on the margin for over 70% of the time in a year. Wood Mackenzie's gas price forecast from the fall of 2014 is used in the base case forecast.
- A carbon tax affects the cost of electricity when natural gas or coal fired generation is on the margin, starting in 2023. Wood Mackenzie's tax assumptions are used in the base case forecast.
- The rapid increase of renewable capacity in the state of California in order to meet their 2020 goal of a 33% renewable portfolio standard. This coupled with the loss of 11,000 megawatts of once-through cooling gas fired generation dramatically increases power prices in the evening while the sun sets.

This forecast is an estimate of the future price of electricity as traded on the wholesale, short-term spot market at the Mid-Columbia trading hub. The forecasted prices are compiled by averaging the costs to run the marginal units for the given time periods specified. More specifically, the cost to generate one megawatt an hour is determined by multiplying the marginal unit's heat rate with its associated fuel costs plus an additional variable O&M surcharge.

2 PLEXOS

To conduct the 2015 wholesale price forecast, Power Management used the PLEXOS Integrated Energy Model (Desktop Edition). PLEXOS is a proven power market modelling and simulation software suite that combines cutting-edge mathematical programming and stochastic optimization techniques with the latest data handling techniques. PLEXOS provides a robust analytical framework to evaluate the impact changing the fundamental assumptions will have on market prices over the next thirty years.

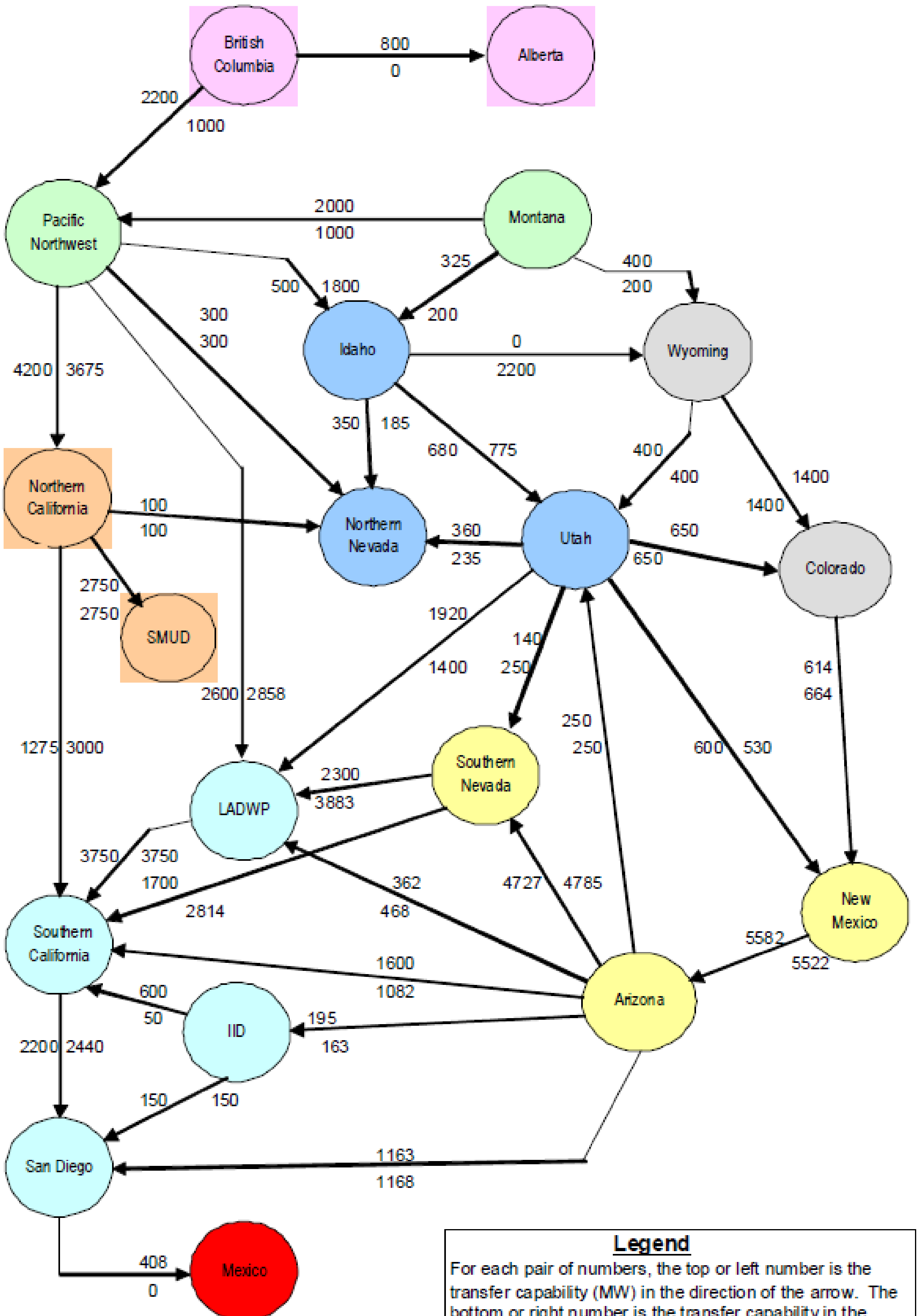
2.1 PLEXOS DATABASE

The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2020 33% California RPS database was chosen as the starting point for our PLEXOS model. The TEPPC has four main functions:

- Overseeing and maintaining public databases for transmission planning

- Developing, implementing, and coordinating planning processes and policy
- Conducting transmission planning studies
- Preparing interconnection-wide transmission plans

The TEPPC database is very granular; it individually identifies every substantive resource and transmission line. While PLEXOS can accommodate this level of detail, modeling runs take an inordinate amount of time to complete. Therefore, for this analysis, this so-called "nodal" data was reorganized into 19 zones with aggregated transmission lines between each zone. All power plants in the database were mapped to their appropriate zones. The image below graphically represents the zonal configuration:



Legend

For each pair of numbers, the top or left number is the transfer capability (MW) in the direction of the arrow. The bottom or right number is the transfer capability in the opposite direction of the arrow.

The TEPPC database contains unit characteristics for over 1400 different generators in the WECC (see image to the right). These unit characteristics were cross referenced with a secondary power plant database provided by E3. Inconsistencies between the two databases were investigated and resolved, usually from the owner's website.

Solar and wind generation profiles were also provided by the WECC TEPPC. These profiles are geographically coordinated and contain hourly capacity factors by day of year.

Because some units have been recently retired or they are scheduled to be retired, the database was cross referenced for a third time with information provided to us by Industrial Info Resources (IIR). This information included retirement dates, new build dates, and new unit characteristics.

Below are the installed capacity assumptions in Mid-C for 2015 and 2035 used in this analysis.

Unit Characteristics

Property	Value	Units
Random Number Seed	93	-
Units	1	-
Max Capacity	270	MW
Min Stable Level	132	MW
Heat Rate	7360	BTU/kWh
VO&M Charge	5.7	$/MWh
Start Cost	14826	$
Rating	270	MW
Min Up Time	8	hrs
Min Down Time	4	hrs
Commit	1	-
Max Ramp Up	2.7	MW/min.
Max Ramp Up Penalty	450	$/MW
Max Ramp Down	2.7	MW/min.
Max Ramp Down Penalty	450	$/MW
Maintenance Rate	5.74	%
Forced Outage Rate	5.5	%
Mean Time to Repair	24	hrs

Mid-C Installed Capacity

Category	2015	2035	Net Change	Units
Hydro	29032	27205	(1827)	MW
Wind	7661	11011	3350	MW
Solar	232	332	100	MW
Biomass	314	483	169	MW
Geothermal	639	907	268	MW
Nuclear	1160	1160	0	MW
Coal	5260	1049	(4211)	MW
CC	7932	8832	900	MW
CT	1938	1938	0	MW
Once-through Cooling	765	390	(375)	MW

3 On-Peak and Off-Peak Hours

The Mid-C price forecast adheres to the standard WECC hour type definitions:

- The on-peak time period begins at hour 7 and ends with hour 22 for Monday through Saturday.
- The off-peak time period begins at hour 1 and ends with hour 6 as well as hours 23 and 24 for Monday through Saturday. For Sundays and holidays all 24 hours are considered off-peak.

4 Water Supply

The amount of time that natural gas fired generation drives wholesale electricity prices depends, in large part, on river flows. In an "average" water year, the basis for this forecast, natural gas generation is the marginal unit for 70% of the time in the Mid-C region. However, river flows can vary substantially from one year to the next. For years with a 25th percentile water (adverse water) or below coupled with expected load growth, the forecast has natural gas fired generation as the marginal unit for up to 85% of the time. With no other changes to the fundamentals, prices will be higher due to the marginal unit being higher in the supply stack. Conversely, years with higher than average water will have lower electricity prices since the extra hydro generation would reduce the proportion of time that natural gas drives prices. However, there is a limit to the amount of extra water the system can absorb. At some point, the extra water is released over spill ways rather than ran through the generation turbines.

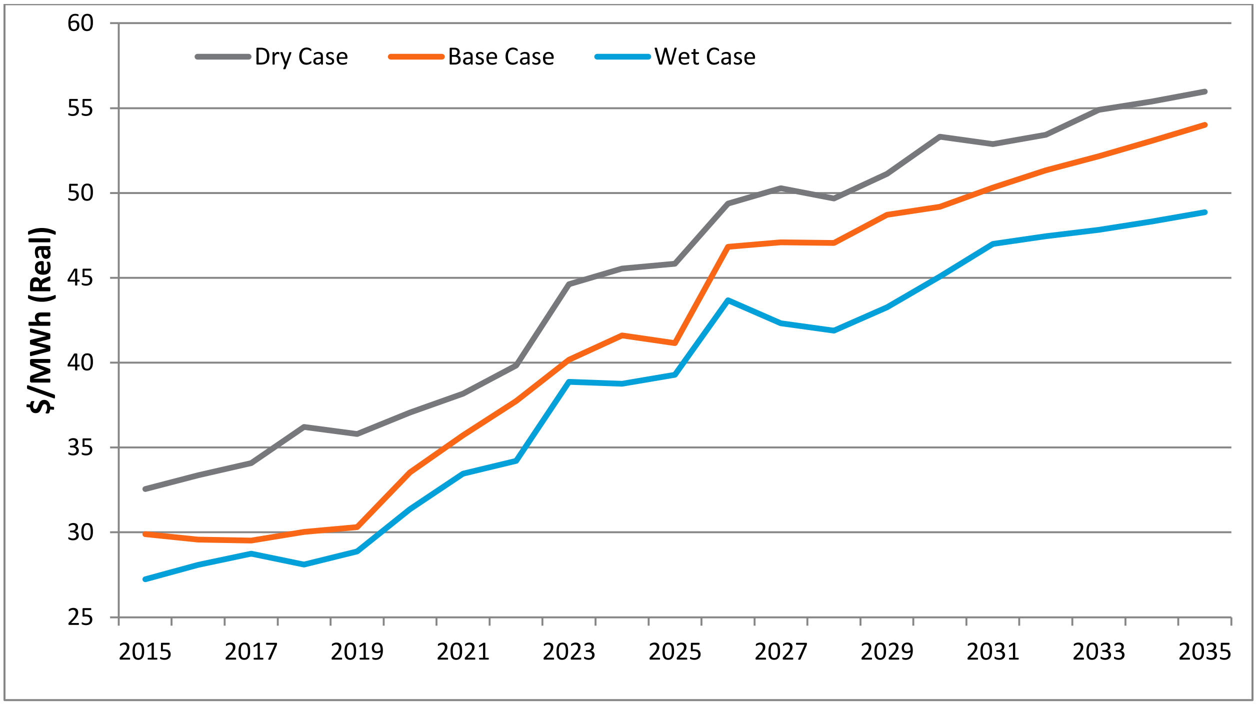


FIGURE 1: MID-C YEARLY PRICES DUE TO WATER YEAR ASSUMPTIONS (FLAT AVERAGES)

5 Weather and Demand Models

Weather is the primary input of our in-house load models therefor a standardized temperature forecast for the major metropolitan areas of the WECC must be created. Power Management has over fifteen years of historical temperature observations for forty plus cities in the WECC. These observations are averaged together by day of year and projected forward for each location.

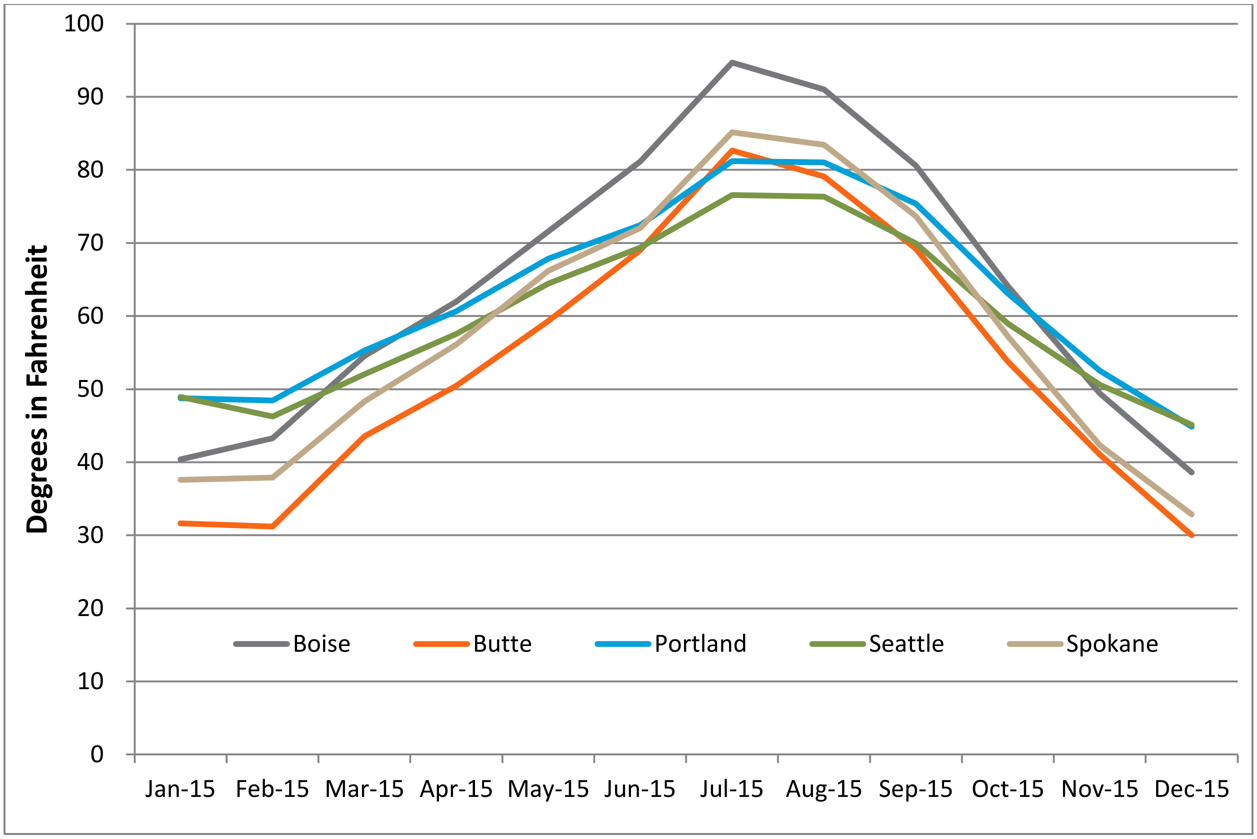


FIGURE 2: SAMPLE HIGH TEMPERATURE FORECAST (MONTHLY AVERAGES)

Once the thirty year weather forecast has been generated for each location, it is then fed directly into our load model. Our load model then performs four key functions:

1. **Nearest Neighbor Lookup –** Historical hourly load data dating back to 2002 has been collected for all 35 balancing authorities in the WECC. This historical data has been mapped to historical temperature data for each city the BA serves load in. This is the first stage to generate our in-house load forecast. The model matches the forward temperatures to historical loads where the temperatures are as close to matching as possible, based on week of year and day of week. This way weekly shapes and seasonality is accounted for.
2. **Regression Equations by BA –** For future days where the weather isn't quite the same as in the past, regression equations will increase or decrease the load values based on heating and cooling degree days. This methodology helps account for record hot streaks or cold snaps that can occur in a near-term forecast if we were to use this model in an operational environment.
3. **Load Growth Assumptions –** When historical days in the past are used for days in the future, two things must occur in order to "true up" the load numbers. The historical load values must be brought to the present tense by applying load growth or decay percentages on a year by year basis. Second, load growth or decay percentages must be applied to the load values on a year by year basis to push the present tense into the future. These forward load growth assumptions are from the FERC Form 714's and are very minute, if not zero values.
4. **Export –** Once completed, the model exports the proper CSV files containing the load forecast to PLEXOS.

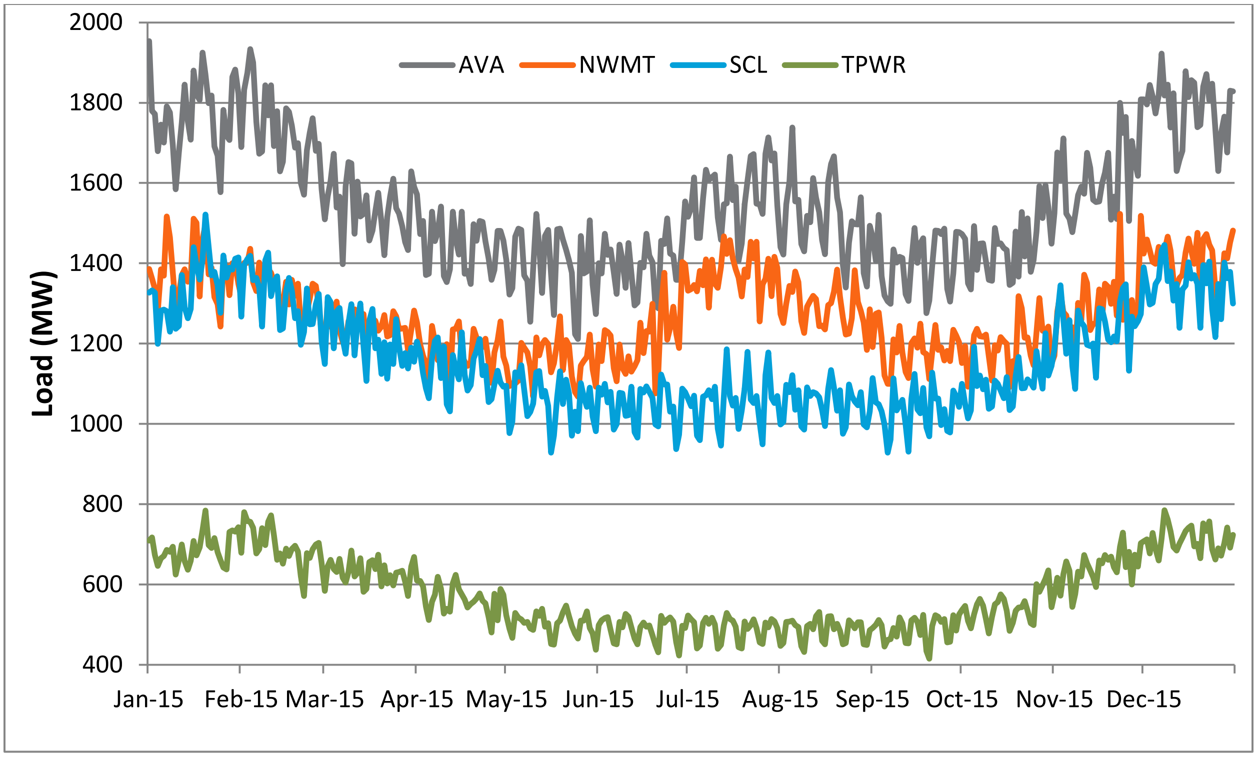


FIGURE 3: SAMPLE DAILY BA LOAD FORECAST (FLAT AVERAGES)

6 GAS PRICE FORECAST

The primary fuel input for the wholesale power price forecast is natural gas prices. Wood Mackenzie's 2014 natural gas price forecast was used in our 2015 power price forecast. Natural gas-fired resources are on the margin at Mid-C in the PLEXOS resource stack about 70% to 80% of the time, depending on the water year. Thus, the PLEXOS results are sensitive to natural gas price assumptions, which holds true in the open market.

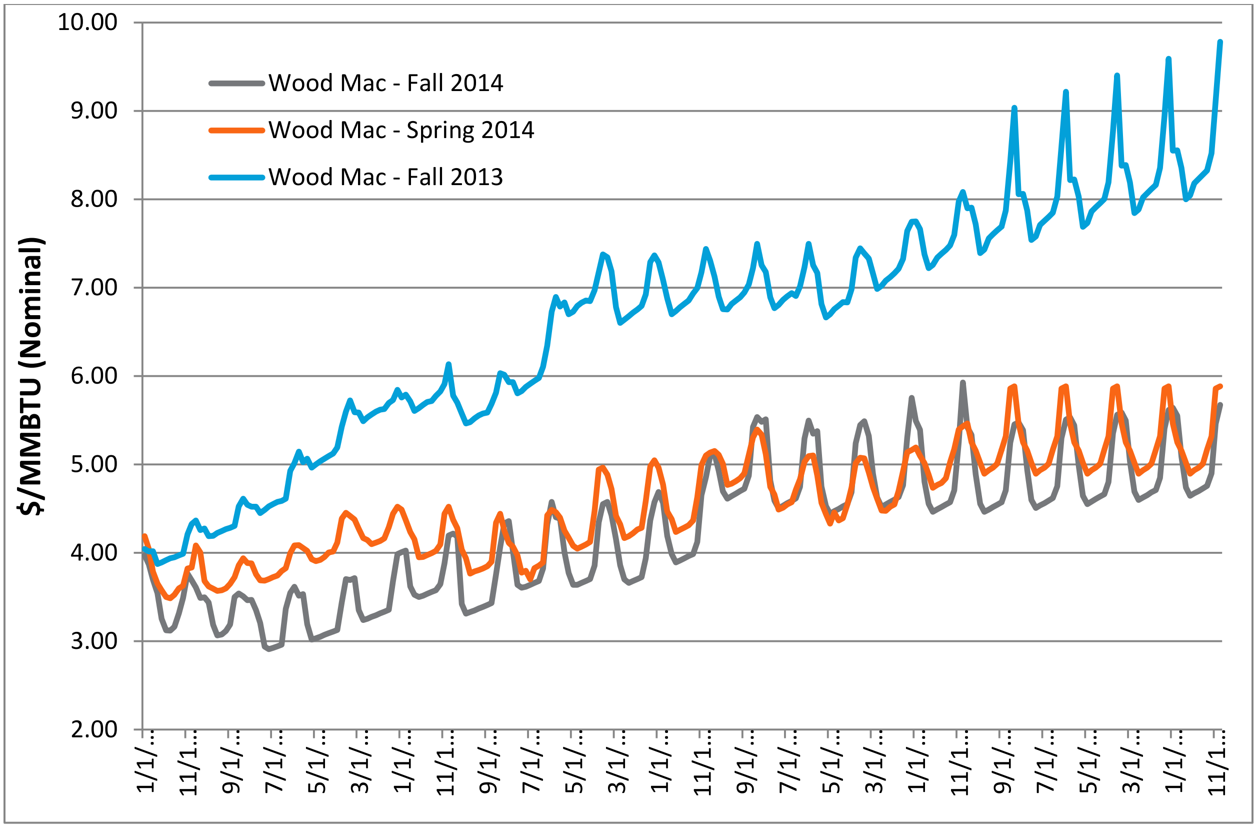


FIGURE 4: NATURAL GAS PRICE FORECASTS (SUMAS)

Natural gas prices at Henry Hub and basis price differentials for all the major natural gas trading hubs are an input to the model. Natural gas prices have been in a steady state of decline for some time now. Wood Mackenzie's forecasts have also seen a steady decline in prices as well.

7 CARBON PRICES

Carbon is the only pollutant with an emission charge in our model, and at this point in time we are currently using Wood Mackenzie's carbon tax assumptions. The potential future pricing of greenhouse gases creates another potential cost risk for thermal resources. CO_2 may eventually be regulated by the federal government. Many states including Washington and Oregon are reviewing their carbon policies. Many utilities and regional planners currently assume incremental costs for CO_2 emissions in their long-term forecasts.

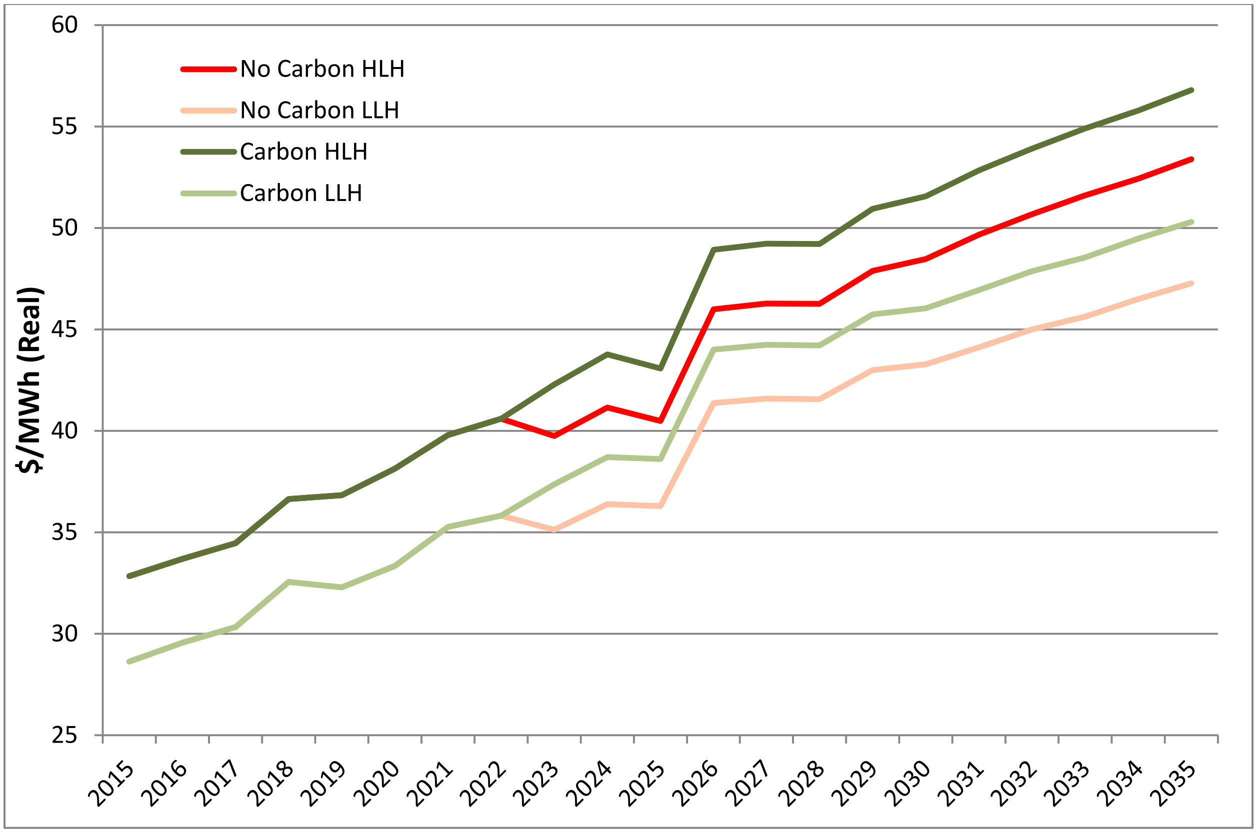


FIGURE 5: MID-C PRICE FORECAST WITH AND WITHOUT CARBON (YEARLY AVERAGES)

In the next four to six years it seems unlikely that there will be a national price on carbon. Wood Mackenzie includes a carbon charge for British Columbia, which has an indexed $28 per tonne charge on CO_2, and for California's indexed floor price for the cap and trade program. For the rest of the WECC they assume a federal charge of $17 per tonne starting in 2023. They also assume that British Columbia and California will move to the federal system as soon as it is instituted. See figure 6.

FIGURE 6: CARBON CHARGES ACROSS TIME - BRITISH COLUMBIA, CALIFORNIA, AND THE WECC

California and British Columbia's pricing are already having an impact on prices at Mid-C. The introduction of the federal carbon tax creates an initial Mid-C price jump of $5/MWh above the average annual price increase in the nominal forecast with the impact rising to $16/MWh by 2034. Without the federal carbon tax the price forecast would be lower from 2023 on.

8 California's 33% RPS by 2020 – Ramping Issues

By 2020, California will have an additional 9,000 megawatts of renewable capacity in its generation stack. Often over looked however, is the planned retirement of over 11,000 megawatts of capacity that uses a technology called "once-through cooling", or "steamers" for short. These steamers use water from the Pacific Ocean to cool their turbines and the State of California wants them retired for environmental reasons. Today, these steamers play a pivotal role in California's supply stack as the more efficient varieties are constantly online serving base load. More importantly, these units can quickly ramp up to meet any curtailment that might occur on the grid.

Due to this loss of peaking generation, peak prices during the hours the sun sets in California (hours vary by time of year) are substantially higher due to the amount of peaking generation needed to compensate for the quick ramp down of solar generation. With the loss of 11,000 MWs of in-state peaking capacity, California needs help from the Northwest to serve load during this time. While it was found that there are less flows into Northern California on average, flows nearly reach maximum transfer capacity during the hours the sun sets.

A day in December was picked to show what happens when California temperatures are mild to cold and it is cold in the Mid-C. Retail demand in California is at its lowest point of the year and loads in Mid-C are at their highest. 2015 power prices in both California and Mid-C are normal for December with the high prices during the super peak being driven by demand, not solar generation going offline. Also the spreads between Mid-C and California prices tighten, which is to be expected. In 2020, we see higher prices throughout the entire day due to higher natural gas prices plus a super peak that is 35 dollars higher due to the sun going down (see Figure 7 and Figure 8).

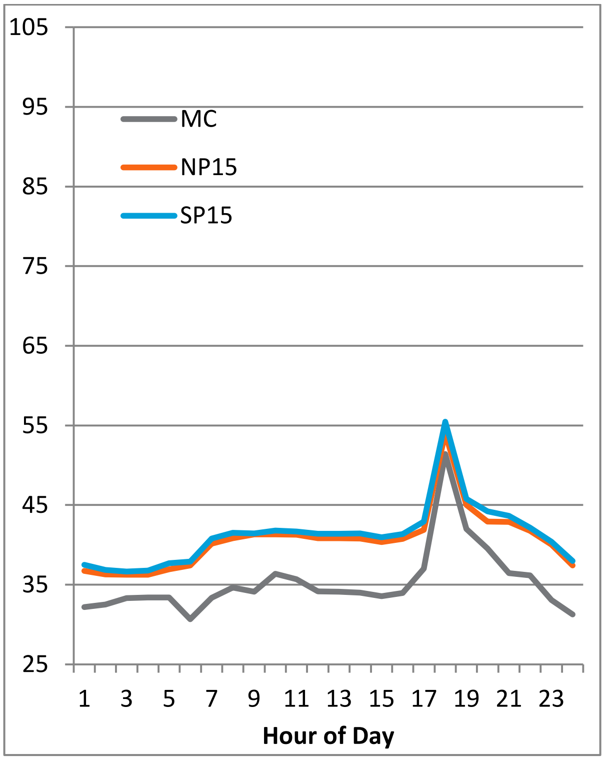


FIGURE 7: 2105 HOURLY PRICES ($/MWH)

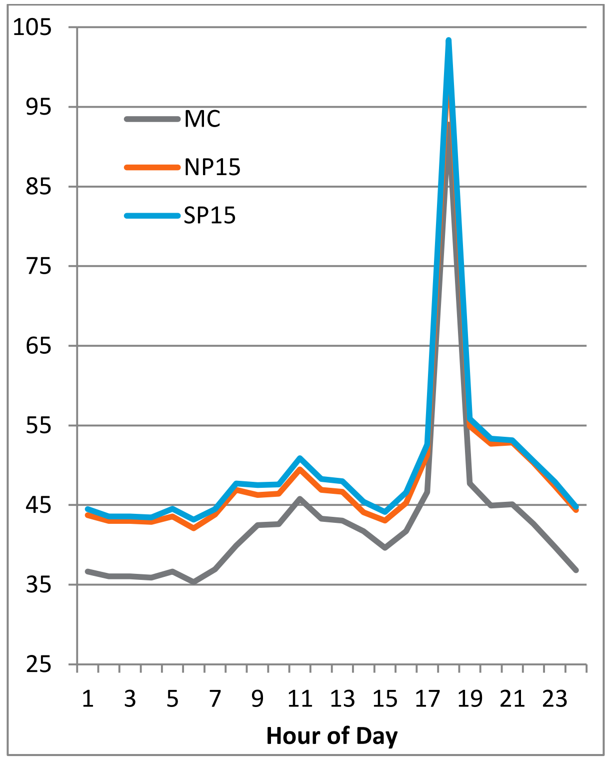


FIGURE 8: 2020 HOURLY PRICES ($/MWH)

Figures 9 and 10 represent Mid-C's supply stack in 2015 and 2020 for the same December day. There are little changes to the stack except for the increased amount of wind generation online in 2020. There is very little extra that is available to sell to California. However, an increased amount of hydro is shaped into the high value peak price period to be exported down to California.

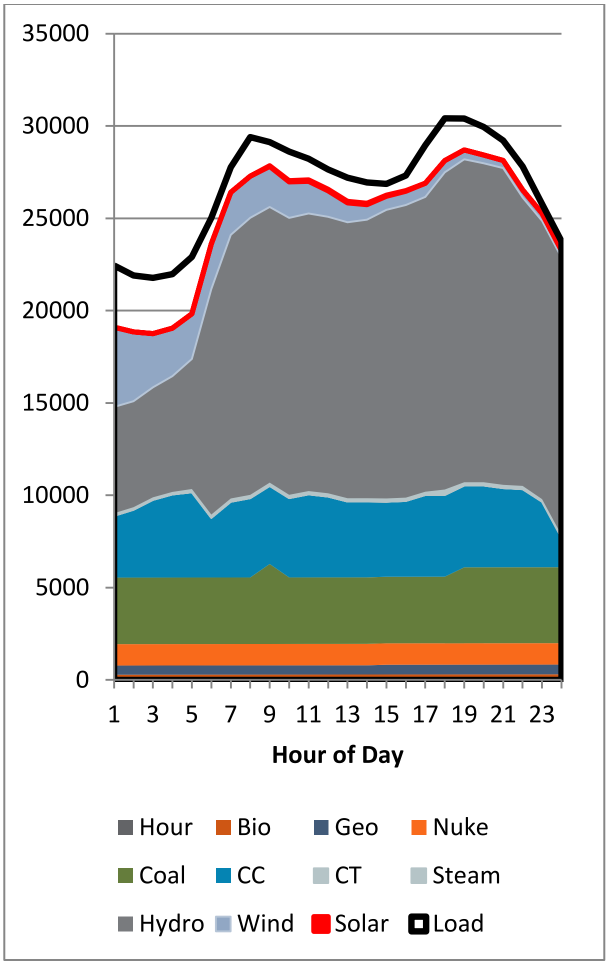


FIGURE 9: 2015 MID-C STACK GRAPH

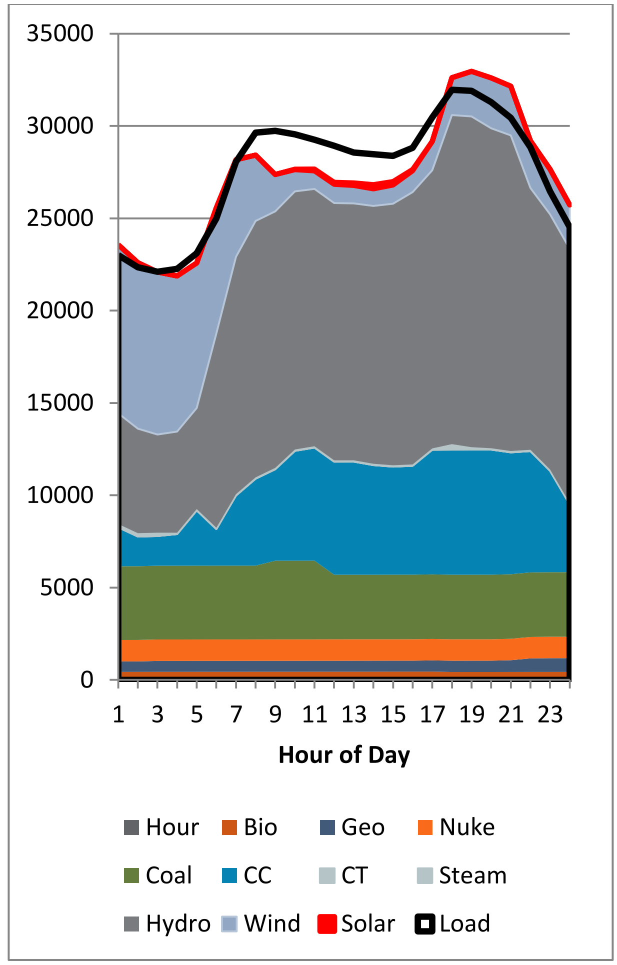


FIGURE 10: 2020 MID-C STACK GRAPH

9 Appendix A – Base Case Price Data

For hourly prices, refer to 2015 Hourly Prices.xlsx.

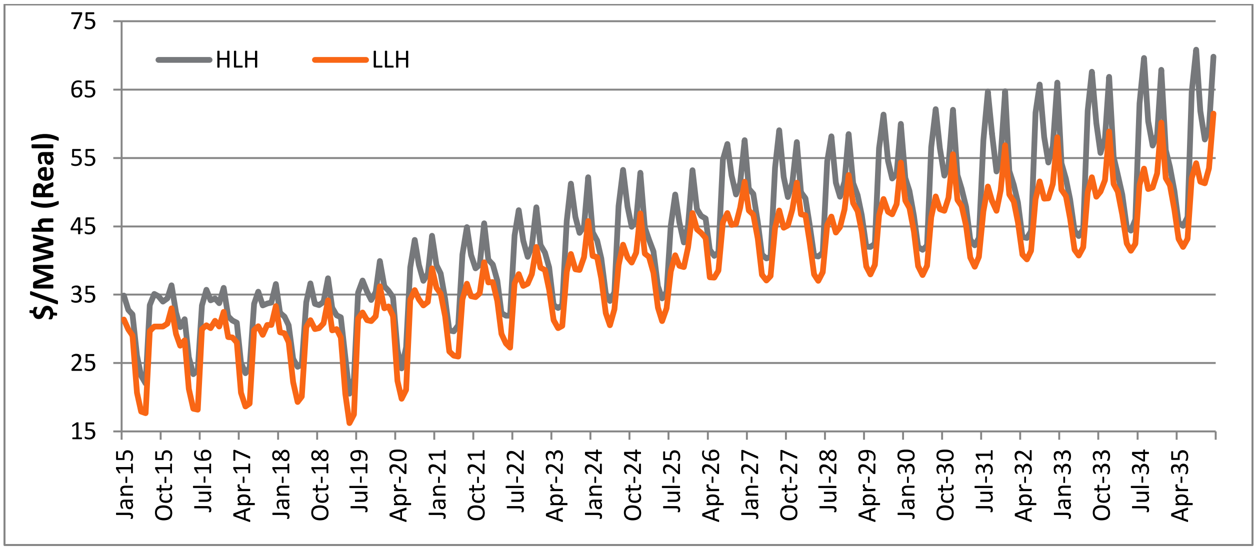


FIGURE 11: MID-C ON-PEAK & OFF-PEAK PRICES (MONTHLY AVERAGES)

Date	HLH	LLH	Date	HLH	LLH
Jan-15	34.89	31.35	Jan-25	44.86	41.02
Feb-15	32.79	29.91	Feb-25	43.05	40.53
Mar-15	32.12	29.02	Mar-25	41.32	38.22
Apr-15	26.07	20.65	Apr-25	36.22	33.11
May-15	23.16	17.88	May-25	34.46	31.16
Jun-15	22.00	17.67	Jun-25	35.39	33.00
Jul-15	33.46	29.67	Jul-25	45.02	38.41
Aug-15	35.10	30.32	Aug-25	49.64	40.78
Sep-15	34.78	30.34	Sep-25	45.60	39.23
Oct-15	34.00	30.35	Oct-25	42.64	39.03
Nov-15	34.46	30.76	Nov-25	45.09	41.91
Dec-15	36.37	33.01	Dec-25	53.20	46.97
Jan-16	32.40	29.29	Jan-26	47.52	44.54
Feb-16	30.25	27.53	Feb-26	46.53	44.07
Mar-16	31.40	28.33	Mar-26	46.16	43.32
Apr-16	25.85	21.22	Apr-26	41.55	37.54
May-16	23.38	18.31	May-26	40.67	37.50
Jun-16	24.00	18.17	Jun-26	41.19	38.51
Jul-16	33.44	29.97	Jul-26	54.77	45.61
Aug-16	35.74	30.53	Aug-26	57.06	46.95
Sep-16	34.17	30.10	Sep-26	52.45	45.24

Oct-16	34.47	31.19	Oct-26	49.67	45.37
Nov-16	33.78	30.32	Nov-26	51.36	47.76
Dec-16	35.98	32.49	Dec-26	57.62	51.51
Jan-17	31.86	28.81	Jan-27	50.49	47.34
Feb-17	31.21	28.77	Feb-27	49.74	46.72
Mar-17	30.90	27.99	Mar-27	45.62	43.22
Apr-17	25.06	20.68	Apr-27	40.89	37.93
May-17	23.53	18.66	May-27	40.29	37.08
Jun-17	24.32	19.06	Jun-27	40.56	37.74
Jul-17	33.68	29.81	Jul-27	53.61	44.76
Aug-17	35.45	30.38	Aug-27	59.05	47.32
Sep-17	33.44	29.12	Sep-27	52.21	44.79
Oct-17	33.70	30.57	Oct-27	49.30	45.11
Nov-17	33.85	30.58	Nov-27	51.38	47.47
Dec-17	36.56	33.35	Dec-27	57.32	51.39
Jan-18	32.35	29.52	Jan-28	49.98	46.78
Feb-18	31.80	29.36	Feb-28	49.10	46.60
Mar-18	30.52	28.05	Mar-28	45.26	42.74
Apr-18	25.64	22.22	Apr-28	40.71	37.95
May-18	24.47	19.30	May-28	40.57	37.04
Jun-18	24.80	20.12	Jun-28	41.15	38.30
Jul-18	33.91	30.25	Jul-28	54.53	45.20
Aug-18	36.68	31.26	Aug-28	58.16	46.43
Sep-18	33.68	29.98	Sep-28	51.38	44.08
Oct-18	33.49	30.13	Oct-28	49.33	44.87
Nov-18	33.95	30.83	Nov-28	51.53	47.45
Dec-18	37.39	34.19	Dec-28	58.49	52.51
Jan-19	33.11	29.77	Jan-29	51.35	48.40
Feb-19	32.00	29.95	Feb-29	49.55	47.25
Mar-19	31.69	28.74	Mar-29	46.62	44.23
Apr-19	25.88	20.51	Apr-29	42.02	39.16
May-19	20.53	16.21	May-29	41.97	37.95
Jun-19	22.70	17.46	Jun-29	42.44	39.39
Jul-19	35.30	31.51	Jul-29	56.46	46.60
Aug-19	37.10	32.42	Aug-29	61.35	48.99
Sep-19	35.43	31.26	Sep-29	54.58	47.14
Oct-19	34.24	31.13	Oct-29	52.00	46.75
Nov-19	35.39	31.82	Nov-29	52.68	48.26
Dec-19	39.93	36.22	Dec-29	59.99	54.35
Jan-20	36.24	32.99	Jan-30	52.08	48.78
Feb-20	35.60	33.29	Feb-30	50.17	47.70
Mar-20	34.65	31.90	Mar-30	46.54	44.23
Apr-20	26.94	22.41	Apr-30	41.98	39.19

May-20	24.21	19.77	May-30	41.55	37.87
Jun-20	27.31	21.07	Jun-30	42.16	39.21
Jul-20	38.98	34.27	Jul-30	56.59	46.33
Aug-20	43.01	35.68	Aug-30	62.15	49.37
Sep-20	39.35	34.33	Sep-30	56.46	47.49
Oct-20	37.02	33.41	Oct-30	52.42	47.27
Nov-20	38.07	33.95	Nov-30	53.94	49.17
Dec-20	43.61	38.85	Dec-30	62.06	55.54
Jan-21	39.33	36.00	Jan-31	52.52	48.88
Feb-21	38.13	35.18	Feb-31	50.52	48.00
Mar-21	34.35	31.85	Mar-31	47.85	45.07
Apr-21	29.79	26.68	Apr-31	43.06	40.45
May-21	29.65	26.08	May-31	42.23	39.11
Jun-21	30.55	25.95	Jun-31	43.29	40.55
Jul-21	40.89	34.30	Jul-31	57.56	47.16
Aug-21	44.87	36.59	Aug-31	64.71	50.82
Sep-21	40.84	34.77	Sep-31	58.56	48.71
Oct-21	38.86	34.65	Oct-31	53.03	47.26
Nov-21	39.35	35.22	Nov-31	55.19	50.28
Dec-21	45.46	39.76	Dec-31	64.77	56.88
Jan-22	40.12	36.81	Jan-32	53.13	49.67
Feb-22	39.41	36.86	Feb-32	51.06	48.64
Mar-22	37.07	34.08	Mar-32	48.48	45.57
Apr-22	32.30	29.28	Apr-32	43.44	40.87
May-22	31.92	27.85	May-32	43.29	40.17
Jun-22	31.92	27.26	Jun-32	44.29	41.44
Jul-22	43.68	36.64	Jul-32	61.62	48.98
Aug-22	47.37	38.02	Aug-32	65.73	51.59
Sep-22	42.94	36.30	Sep-32	58.10	49.05
Oct-22	40.56	36.60	Oct-32	54.35	49.10
Nov-22	42.10	38.02	Nov-32	56.71	51.20
Dec-22	47.79	41.97	Dec-32	66.04	58.05
Jan-23	42.28	38.95	Jan-33	54.26	50.38
Feb-23	41.13	38.62	Feb-33	51.95	49.41
Mar-23	39.01	35.72	Mar-33	48.95	46.16
Apr-23	33.49	31.26	Apr-33	44.32	41.55
May-23	33.06	30.13	May-33	43.60	40.75
Jun-23	33.46	30.45	Jun-33	44.61	41.95
Jul-23	45.76	38.35	Jul-33	61.91	49.97
Aug-23	51.26	40.95	Aug-33	67.60	52.20
Sep-23	46.39	38.72	Sep-33	60.11	49.32
Oct-23	44.06	38.64	Oct-33	55.74	50.09
Nov-23	44.97	40.47	Nov-33	57.91	51.76

Dec-23	52.17	45.78
Jan-24	44.14	40.68
Feb-24	42.92	40.50
Mar-24	40.32	37.37
Apr-24	35.18	32.32
May-24	34.09	30.52
Jun-24	35.34	32.89
Jul-24	47.96	39.32
Aug-24	53.25	42.30
Sep-24	47.90	40.43
Oct-24	44.92	39.72
Nov-24	45.89	41.16
Dec-24	52.86	46.90

Dec-33	66.89	58.88
Jan-34	55.18	51.20
Feb-34	52.58	50.10
Mar-34	49.68	46.70
Apr-34	44.91	42.49
May-34	44.37	41.41
Jun-34	46.00	42.48
Jul-34	63.01	51.05
Aug-34	69.63	53.45
Sep-34	60.39	50.47
Oct-34	56.82	50.69
Nov-34	58.36	52.74
Dec-34	67.92	60.20
Jan-35	56.18	52.03
Feb-35	53.70	51.04
Mar-35	50.17	47.41
Apr-35	45.55	43.15
May-35	45.10	41.98
Jun-35	46.34	43.16
Jul-35	64.61	52.05
Aug-35	70.87	54.23
Sep-35	61.88	51.52
Oct-35	57.71	51.29
Nov-35	59.37	53.51
Dec-35	69.83	61.50