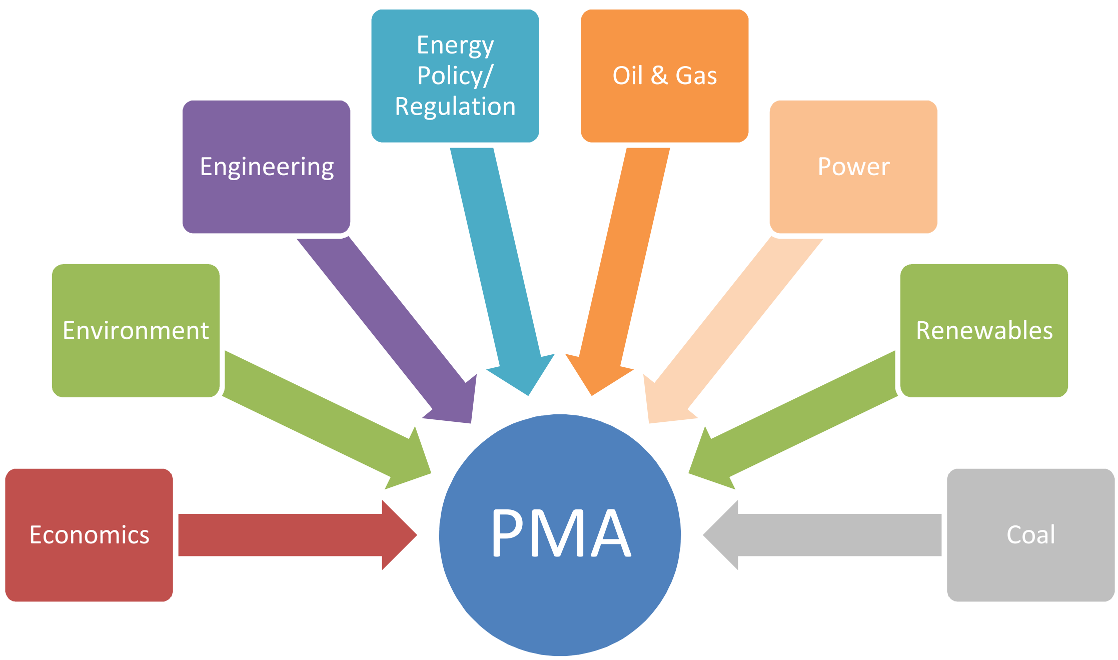
Power Market Analysis (PMA)

Summer of 2014 Analysis

Covering Fuel Consumption, Power Price, & Company Performances



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March, 16th 2014

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Preface

Dear Reader,

This report is intended to give a broad view of the power markets and their impacts on fuel consumption, power prices, and a general example of how the future may impact generation fleets. Though the report is 79 pages it is still only a small fraction of what we could present.

We are able to build off this analysis to produce any custom view or further analysis that is directly your concern. The power markets touch many, from traders, energy managers, fuel buyers, plant operators, government officials to fuel producers and many more. We have the ability to help you better understand the market by explaining what has happened and how the future can unfold and what you can do to prepare for that future.

I wanted to be able to differentiate this report from many other reports on the power markets by not regurgitating information which is readily accessible from various government sites and to offer real bottom-up analysis. I truly hope you are able to build questions for yourself and your teams as you go through this report. Is my company aligned with the potential of the future? How likely are some of these outcomes? What can I do to better position myself given this analysis?

At All Energy Consulting, we have taken the time to understand the market from the ground up, so we can guide you through the mazes and hurdles that the future offers.

Please do consider subscribing to our service or reaching out to me for consulting assignments.

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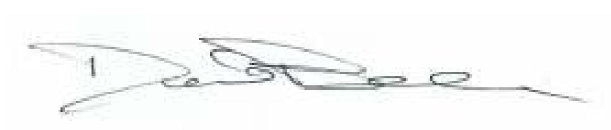

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Executive Summary

Summer of 2014 will differ from previous years as a result of one of the coldest winters in decades. The weather will continue to play a key role in how the summer unfolds. An in-depth and rigorous analysis is done on fuel consumption, power prices, and the top 10 utilities generation fleet. Power Market Analysis (PMA) processed 19 different potential sensitivities that could impact the power markets and presents key findings from those runs.

Gas demand is the most sensitive variable being easily impacted by elements such as changing commodity prices to weather. With the current forward curve of Henry Hub, prices this year will increase +23%, relative to 2013. This price change will significantly reduce gas demand in the power sector, assuming normal weather. Coincidently, the base case is showing a 23% drop in summer power gas demand compared to the four year average. The recent EIA Short Term Energy Outlook (STEO) is not anticipating much drop in power demand in 2014 relative to 2013. In order for that to happen, there are several changes in key variables needed, in some cases by themselves or in combination with other variables, to mitigate the gas demand drop in the power sector compared to 2013. An unusually warm span of weather can make up for the drop in gas, but this would have to be even warmer than the record setting summers of recent. The Western drought could impact the gas demand in the sector by almost 7% if the drought was similar to that in 2001. A price drop of almost $1/MMbtu could produce no drop in demand from the power sector. In addition, a further decline in negative basis could also add to gas demand. All this is displayed in the analysis below.

Power prices across the US will perform differently depending on the existing infrastructure and current generation fleet. There are areas which are very sensitive and can easily experience significant prices spikes – NY and ERCOT. Many areas are directly tied to natural gas prices. Other

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areas are showing little impact to power prices even if gas prices were to fall. There are usually trading arbitrages in power markets as the ability for the market to efficiently compute all possible changes is limited. Power market analysis requires a platitude of skill sets which then must be combined and deciphered to produce a cohesive picture. Many times, by the time the process is complete, the market has moved on. PMA subscribers get fresh daily runs, so whenever the market shifts, PMA is there with a snapshot of possible scenarios. The various power markets have their own characteristics. This can be seen in the analysis below.

The top ten utilities fleet, by size of generation capacity, was reviewed under the various 19 cases. A proxy calculation was made on how the fleet could be impacted from the base case. Some fleets were much less risk averse to changes in the market. Whereas others could see a devastating profitability change if certain sensitivities come to fruition. All fleets would like to see a warmer than usual summer, but NRG and Calpine fleet can hit the lottery if this were to happen. There are many business strategies that can be designed once the knowledge is made on what makes the fleet “tick”. More company fleets are available upon request.

The Summer 2014 PMA analysis demonstrates the vastness of analytical capability and information available if power market analysis is well thought out and performed. PMA is designed for flexibility to offer multi-faceted views of the power market. There is so much more available in terms of reporting. If you would like additional information from these runs please contact us at dkb@allenergyconsulting.com or at 614-356-0484. Also customized cases can be done for a fee.

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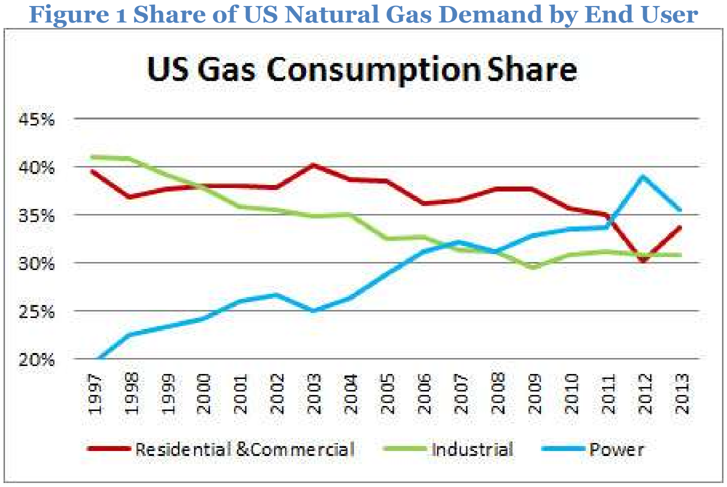
Input View

The key to any analysis is understanding the story of the major inputs going into an analysis. The major inputs for power analysis are the natural gas markets, coal markets, and the power infrastructure.

Natural Gas

US power represents the largest end user for US natural gas demand – See Figure 1.

Figure 1 Share of US Natural Gas Demand by End User



Over the past few summers, gas consumption in the power sector has been hitting record levels of consumption. Over the past 12 years, the average growth of natural gas demand in the power sector for the summer months has been around 3% a year. See Figure 2.

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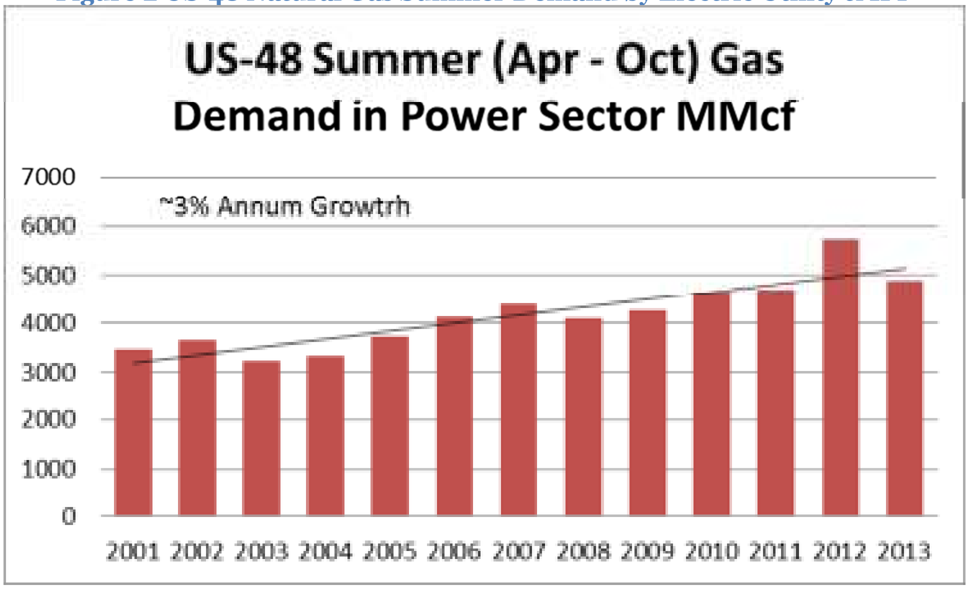
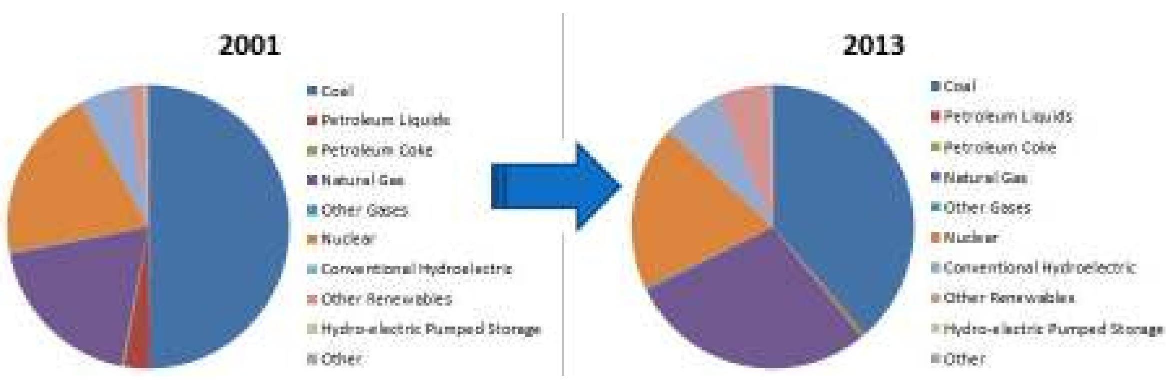
Figure 2 US-48 Natural Gas Summer Demand by Electric Utility & IPP



The increase of gas demand has come from the natural growth in load demand and of recent, the displacement of coal generation due to retirements and economics. Renewable generation has had a negative impact on natural gas demand as renewables replaced some of the incremental load growth. If renewables stayed the same level as in 2001 – ~16% more gas demand would likely be needed.

Figure 3 US Summer Power Generation by Fuel



The drop in natural gas prices had a big role in the change in natural gas demand. However, price is not everything in natural gas demand in the power sector. From 2002 to 2008, we observed a 15% annualized growth of natural prices while demand in the power sector grew nearly 4% on

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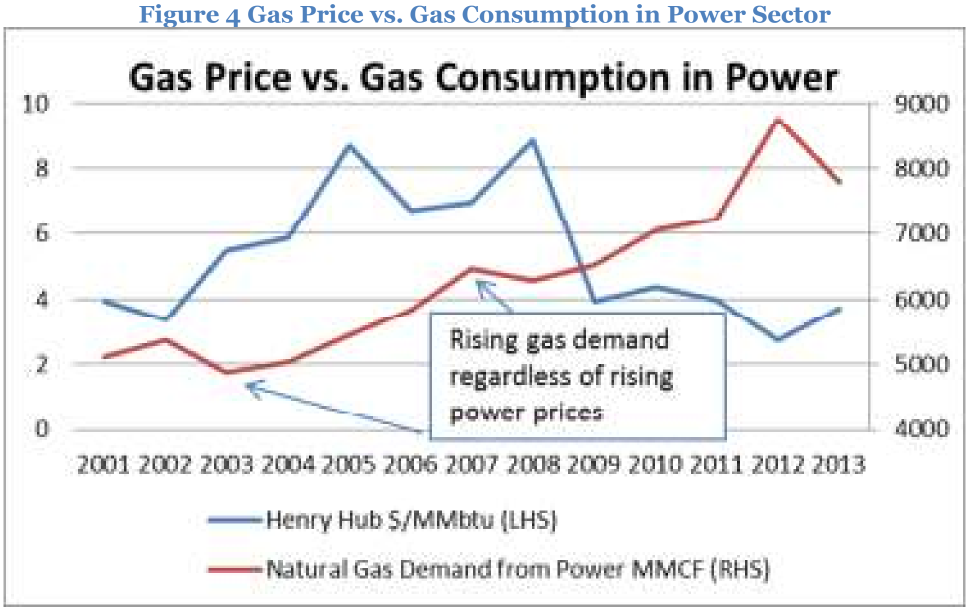
annualized basis. See Figure 4. Most people outside the energy space do not realize this. The reason for this was the incremental load growth had to be met, and the spare capacity in the markets came from the over build out of gas units in the later 90's and early 2000's. Load growth was averaging 1.2% from 1998-2008. The rising price of natural gas demand would not stop gas being used in the power sector. Therefore, the load growth was expected to add around 1 Bcf/d of gas demand each year.

Figure 4 Gas Price vs. Gas Consumption in Power Sector



Three areas are slowing the growth of gas demand in the power sector economy, the push on energy efficiencies initiatives, and the huge renewable development. Renewable growth is likely to slow down, now that gas prices are putting a damper on renewable economics. Energy efficiencies still have room to alter the demand landscape, but the big unknown is the economic recovery and the rise of manufacturing.

Coal

Coal consumption has been drastically altered over the past few years. The recent changes have less to do with the environmental attack on coal generation versus the economic value created by low natural gas price. The

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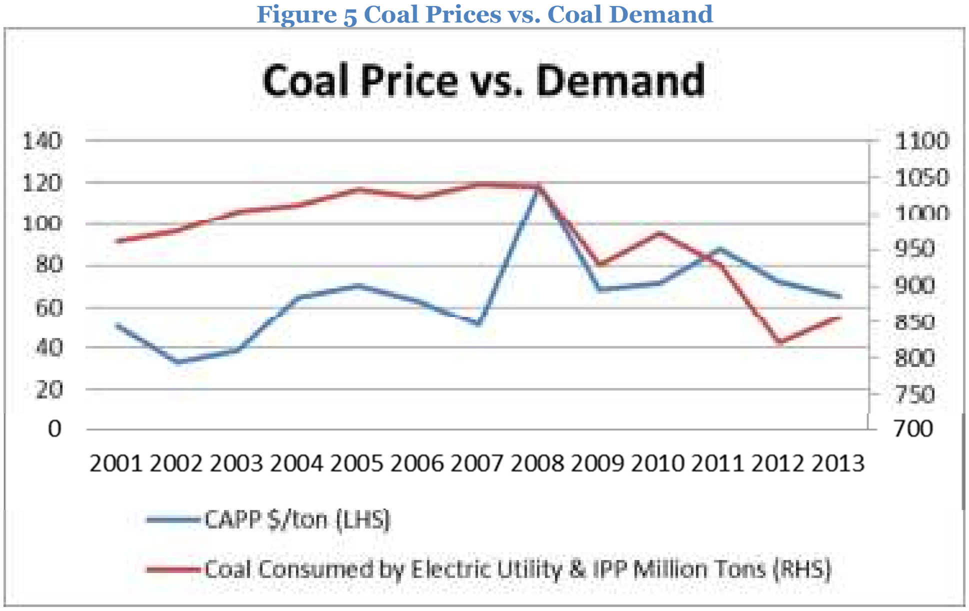
environmental attack on coal mining has been successful in keeping coal prices quite high relative to the drop in demand.

Figure 5 Coal Prices vs. Coal Demand



The environmental war on coal generation is yet to be seen as much of the major coal retirements have yet to be seen. The largess of coal retirements over the past few years, 32 GW since 2009, are units that barely run in the first place as a result to low gas prices.

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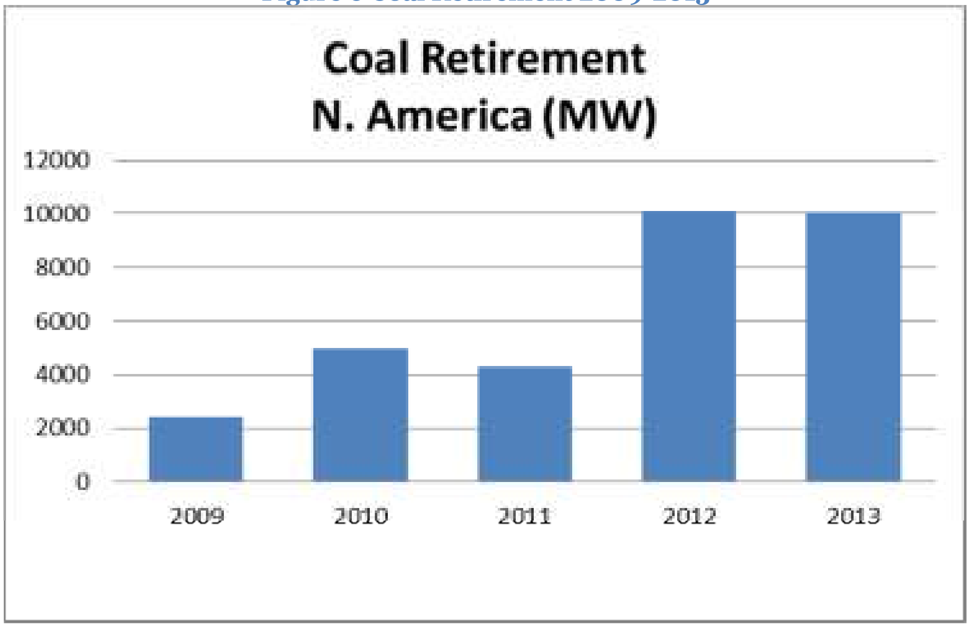
Figure 6 Coal Retirement 2009-2013



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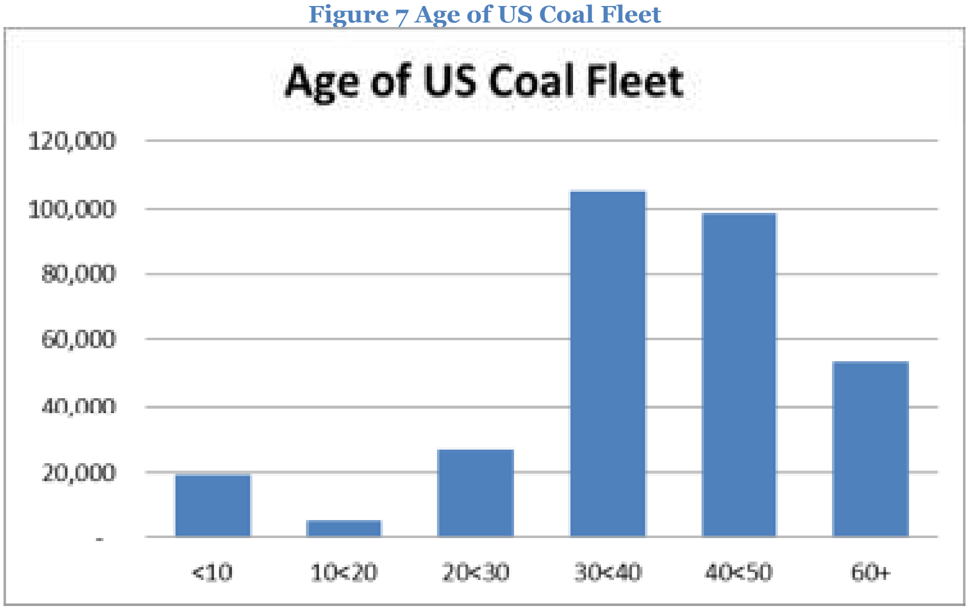
The biggest looming impact will occur in 2015-2016, as EPA Mercury and Air Toxics Standards (MATS) go into effect. This essentially requires a large investment to be made in coal plants. The rule will require a combination of flue gas desulfurization (FGD), selective catalytic reduction (SCR), dry sorbent injection system (DSI), baghouse, or an electrostatic precipitator (ESP). The largest cost will likely be the FGD. About 40 percent of the current coal fleet currently does not have an FGD installed. This puts at risk ~120 GW. The decision to invest in additional equipment in face of a potential low gas price environment makes odds low to keep a coal facility running, particularly if the plant is already near its end of life. In addition, for some plants the investment could equal to the same amount as a brand new gas plant.

Figure 7 Age of US Coal Fleet



Power

Very hot summers have led to larger than expected load in the summer for the past few years. If "normal" weather, returns a drop in demand relative to the past few years becomes very likely. Or is there a new normal? See Figure 8. Normal cooling degree days (CDD) and heating degree days (HDD) are defined by the National Oceanic and Atmospheric

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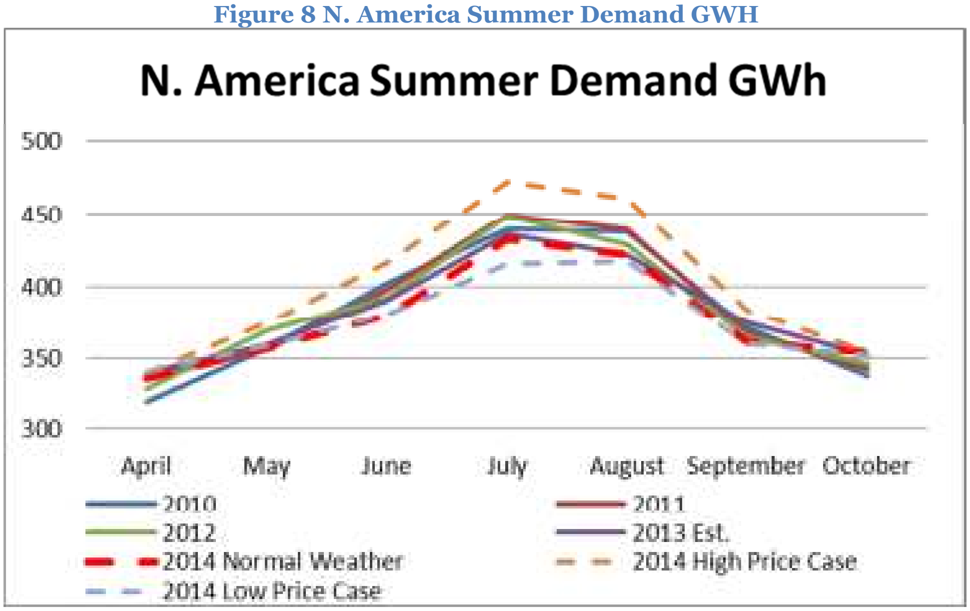
Administration (NOAA). According to NOAA, “Climate Normals are the latest three-decade averages of climatological variables including temperature and precipitation. This product is produced once every 10 years. The 1981–2010 U.S. Climate Normals dataset is the latest release of NCDC’s Climate Normals.”

Figure 8 N. America Summer Demand GWH



PMA process can be adapted to run any set of CDD and HDD. Subscribers have access to create their own unique outlook. The current range of demand is based on modifying the CDD and HDD to the 4 year high across N. America and then modifying GDP by 0.5%. An entire region being high perhaps is too strong, but this increase load can also represent a case with extreme outages plus hot conditions.

In terms of the infrastructure input into the model, PMA is keeping track of over 1.2TW of capacity in N. America. A regional breakdown can be seen in Figure 9.

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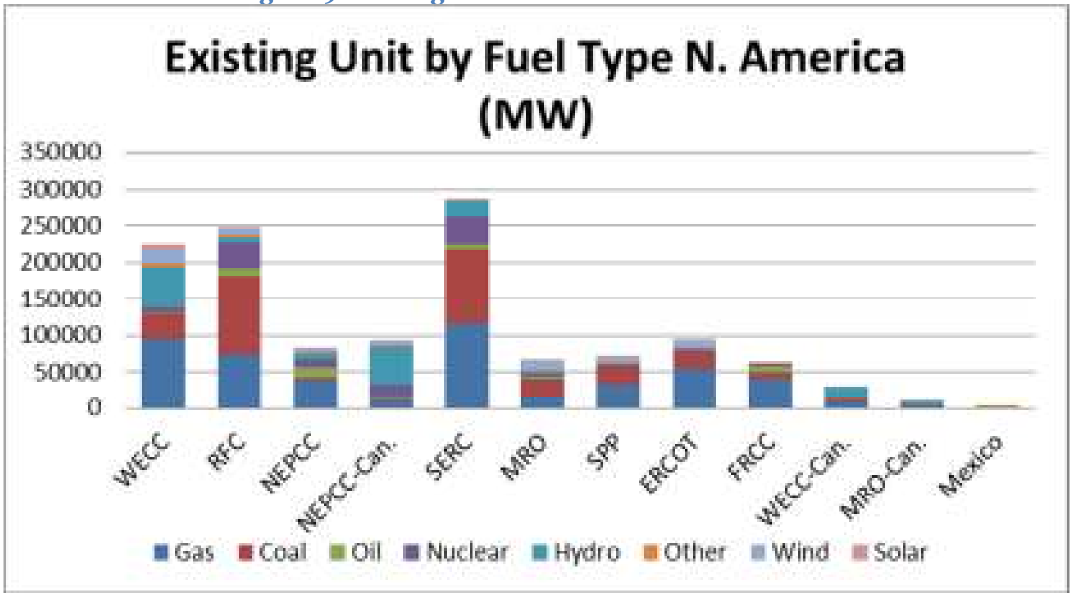
Figure 9 Existing Generation Units in N. America



Our current projections expect retirements to total 74 GW with coal representing over half those retirements – Figure 10. As discussed above, most of those retirements will be seen in 2016. Given most coal generation lies in the eastern part of the US, there will likely be greater impacts of retirement in those regions – Figure 11.

Figure 10 Retirement by Fuel Type

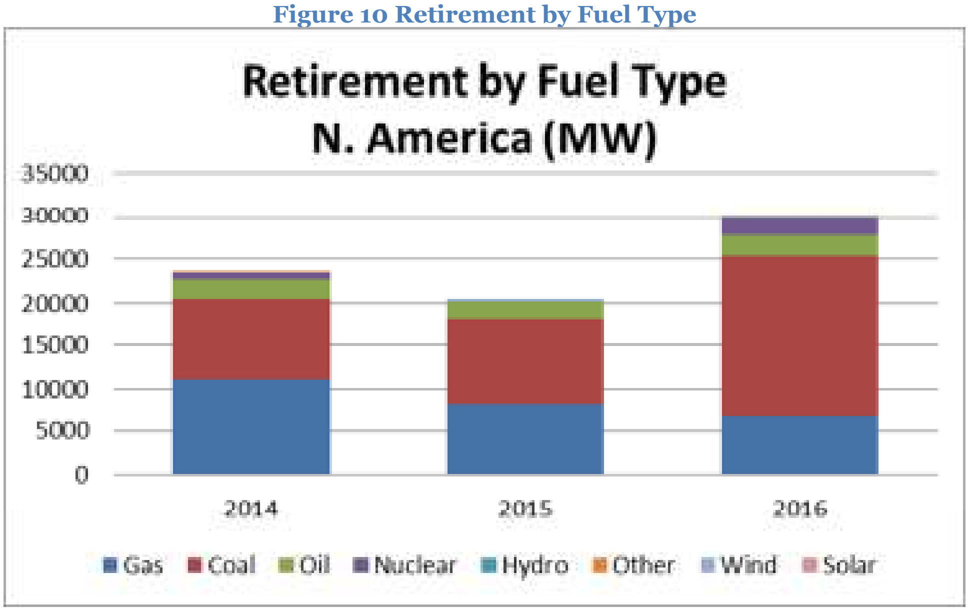


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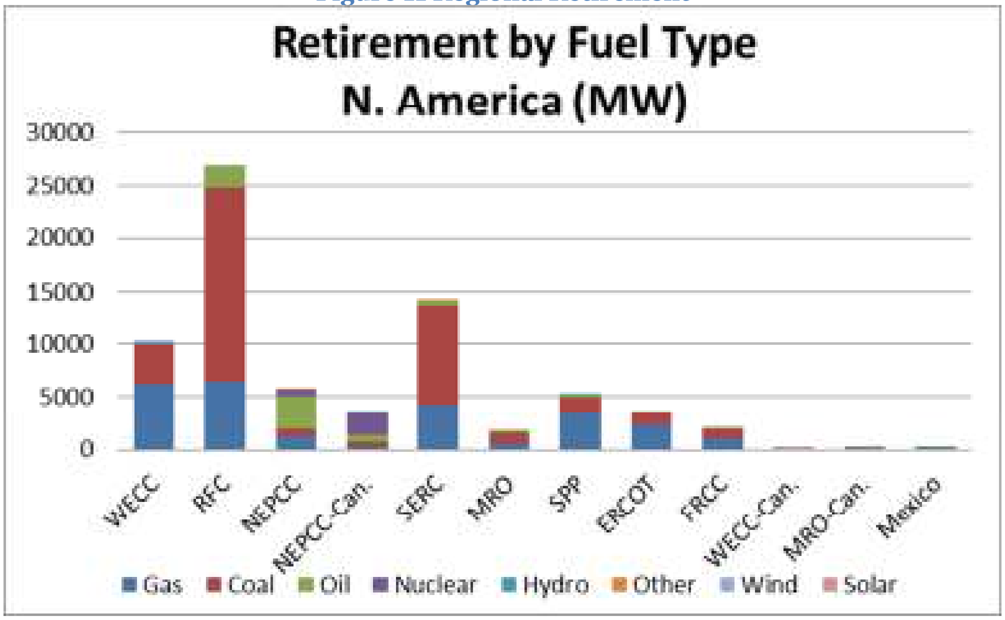
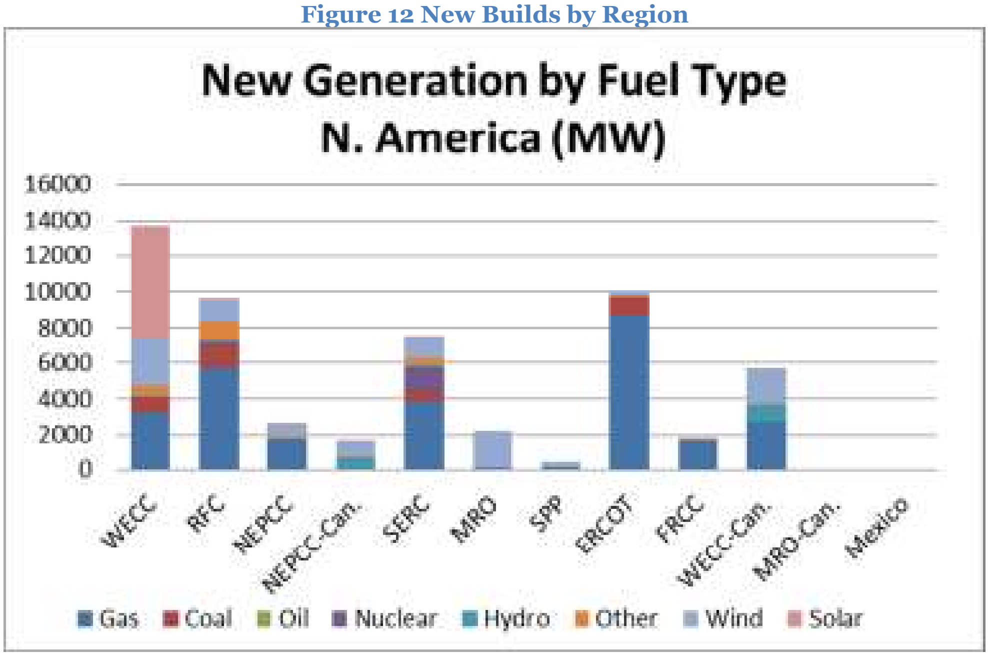
Figure 11 Regional Retirement



The new power plants projected are mainly gas, wind, and solar plants with a total of only 56 GW. The areas with the most new builds are areas with large retirements or large renewable programs – see Figure 12. New resources came from the EIA-860 plus additional research.

Figure 12 New Builds by Region



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Results

Many sensitivities were examined in order to fully understand the potential outcome of 2014. Given the drought situation in the West, a hydro sensitivity was developed using the 2001 hydro and weather condition. 2001 abnormal weather is partially to blame for the California power crisis that occurred. In addition, two gas basis views were added to get a sense of the significance of basis changes.

Given natural gas prices have varied so much in the past few years, Henry Hub price iteration cases were developed to explain the various sensitivity to natural gas price on power and fuel consumption. We also ran two weather cases with modification of GDP to produce the wide band of demand.

All these cases will encompass the final outcome of summer 2014. The range here can be used to guide a fundamental view on power and natural gas prices. In addition, the range can be used to assist in trade or assets deals in order to understand the risks and rewards.

Natural Gas Consumed in Power Sector

Power Market Analysis (PMA) is focused on the Electric & IPP sectors of the power generation occurring in the US-48. This represents roughly 95% of the electric power usage. In order to produce the total power sector demand, an annual factor of 1.048 is recommended. See Figure 13. PMA subscribers have access to the monthly adjustment factors.

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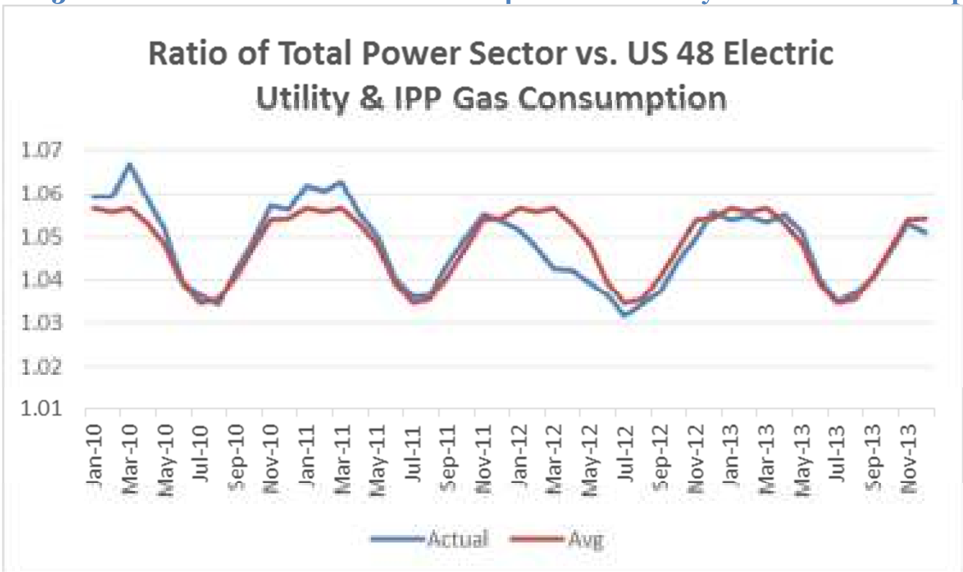
Figure 13 Ratio of Total Power Sector vs. US 48 Electric Utility & IPP Gas Consumption



Validation of PMA results can be found in the Appendix. Overall the PMA model is able to backcast within a reasonable range of producing annual deviations of around -6%.

The PMA summer gas demand sensitivities are presented below in Million MMbtu and Bcf/d.

Figure 14 PMA Natural Gas Demand Million MMbtu

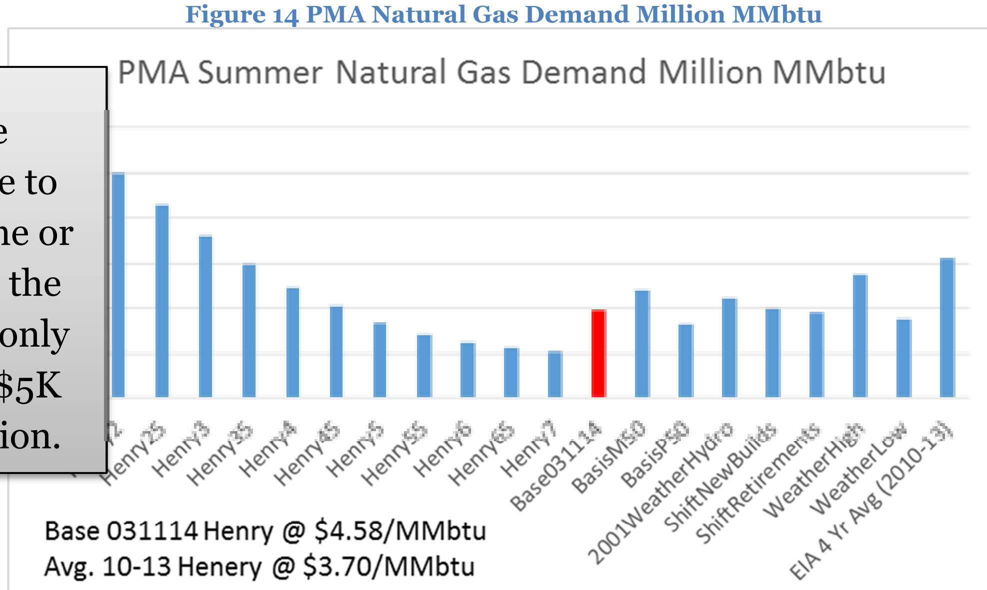


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Figure 15 PMA Summer Natural Gas Demand Bcf/d

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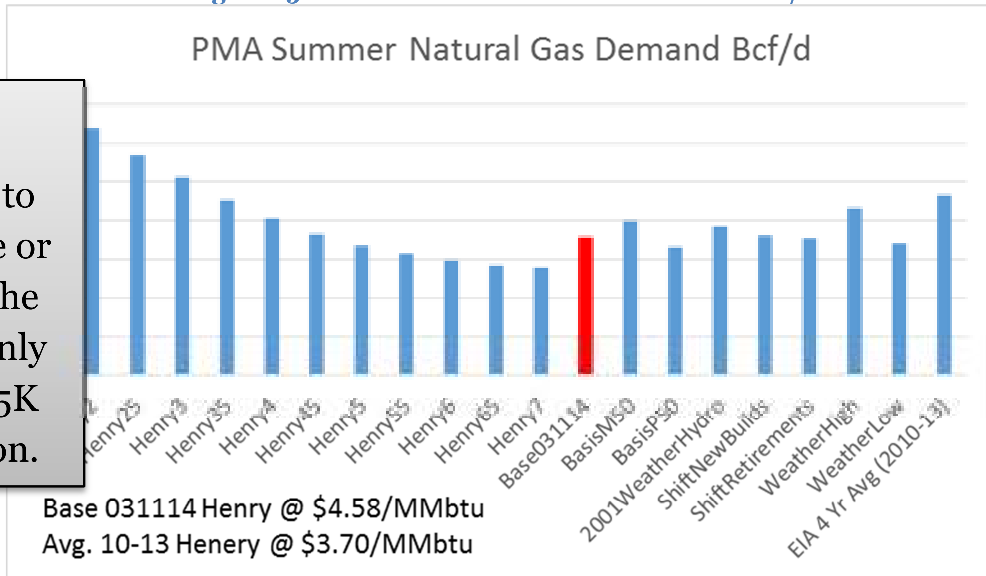

The sensitivities show the major difference in this summer demand relative to the past four years, assuming normal weather, will be a result of the price increase of $0.88/mmbtu. If price was closer to the $3.70/mmbtu, it would produce a similar natural gas demand as that which occurred the last four years. This supports the discussion above noting the coal retirements that have occurred (~30 GW) are mainly coal units which do not run that much.

Recent EIA Short Term Energy Outlook (STEO) notes 22 Bcf/d is expected from the power sector for 2014. This is essentially the same figure as it was in 2013 - ~22.34 Bcf/d. However, based on current forward pricing of natural gas, the prices in 2014 will be almost $0.85/MMbtu higher. Based on the above sensitivity, a $0.85/mmbtu change in price in the $4/mmbtu range can impact gas demand by 2-4 Bcf/d.

The current PMA base case with calibration and adjustments to produce the equivalent power sector demand is showing 19 Bcf/d power sector demand for 2014. In order to produce the 22 Bcf/d seen in the EIA STEO, natural gas prices or basis needs to fall by $0.50/mmbtu and/or an

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increase in load of 3% from the normal case is needed. A combination of price, load, and reduced Hydro capability can also be a solution to equal the EIA STEO projection. The 2001 Hydro and weather condition by itself will not equal the demand change as a result of the price change. The 2001 Hydro and Weather case impacts the summer by 1.3 Bcf/d.

A monthly view of demand is presented below in both Million MMbtu and Bcf/d. The excel file is available for PMA subscribers.

Figure 16 PMA Summer Gas Demand Million MMbtu by Month

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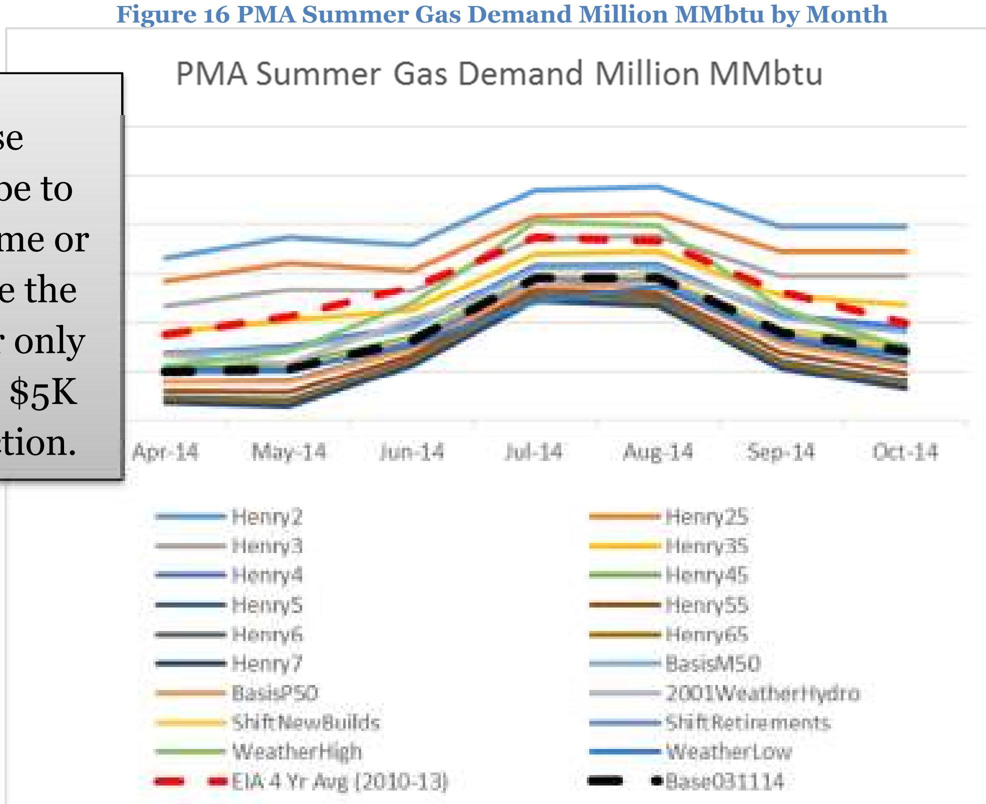

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Figure 17 PMA Summer Gas Demand Bcf/d by Month

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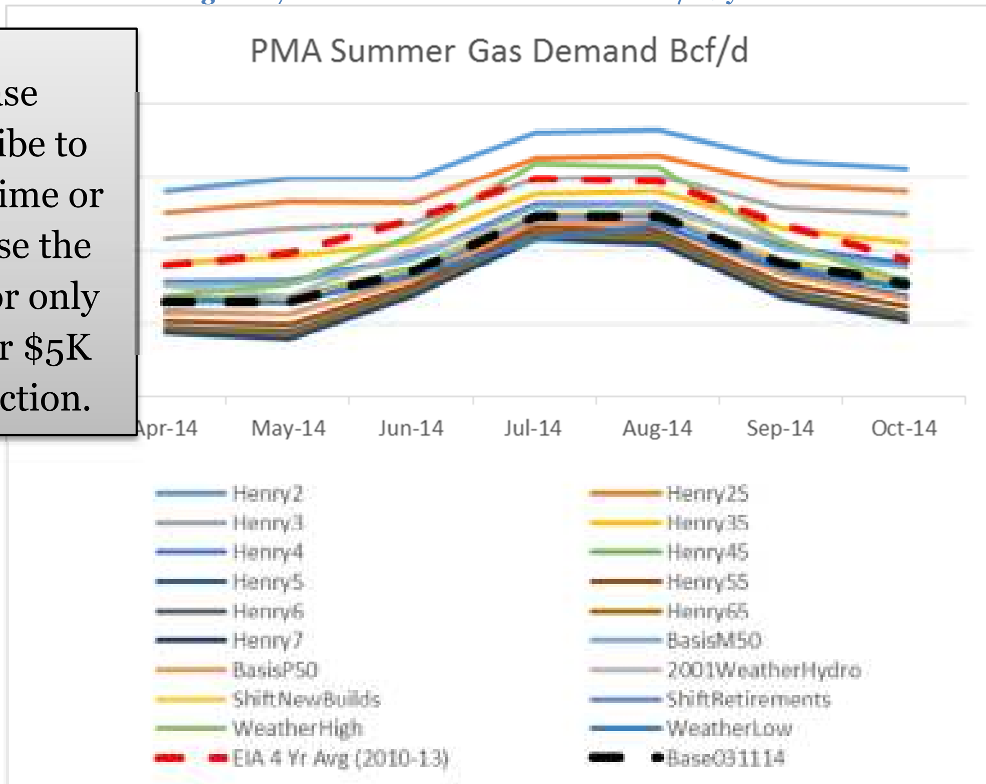

Coal Consumed in Power Sector

PMA is focused on the Electric & IPP sectors of the power generation occurring in the US-48. This represents roughly 99% of the electric power usage. In order to produce the total power sector demand, an annual factor of 1.01 is recommended. See Figure 14. PMA subscribers have access to the monthly adjustment factors.

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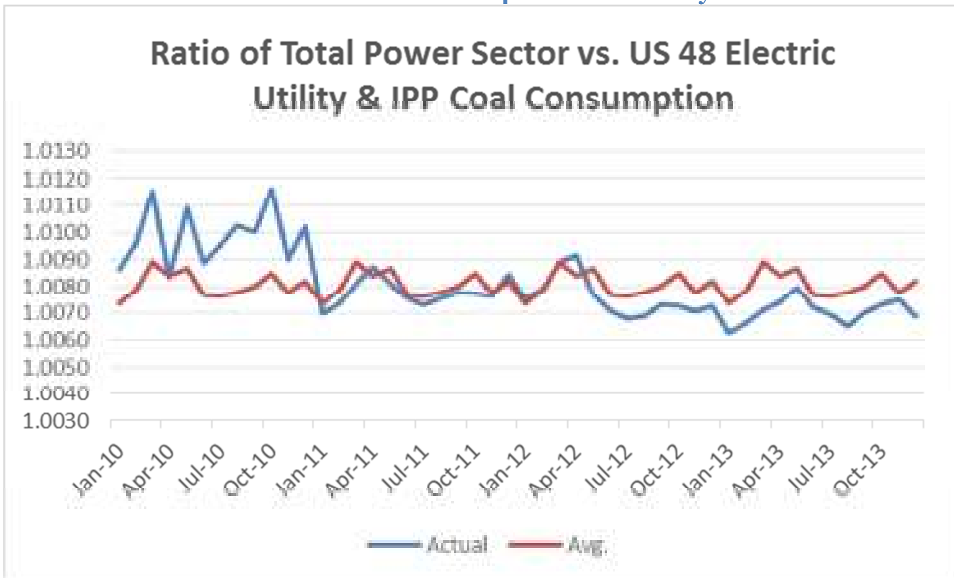
Figure 18 Ratio of Total Power Sector vs. US 48 Electric Utility & IPP Coal Consumption



Validation of PMA results can be found in the Appendix. Overall the PMA model is able to backcast within a reasonable range of producing annual deviations of around -2%.

The PMA summer coal demand sensitivities are presented below in Million MMbtu and kTons/day.

Figure 19 PMA Summer Coal Demand Million MMbtu

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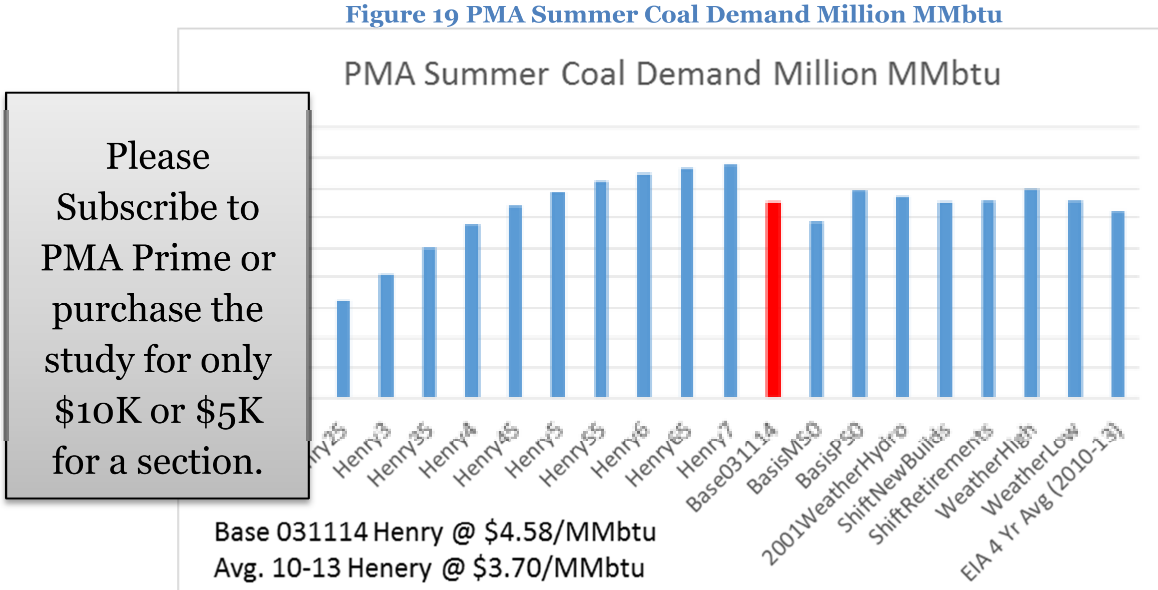

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Figure 20 PMA Summer Coal Demand kTons/Day

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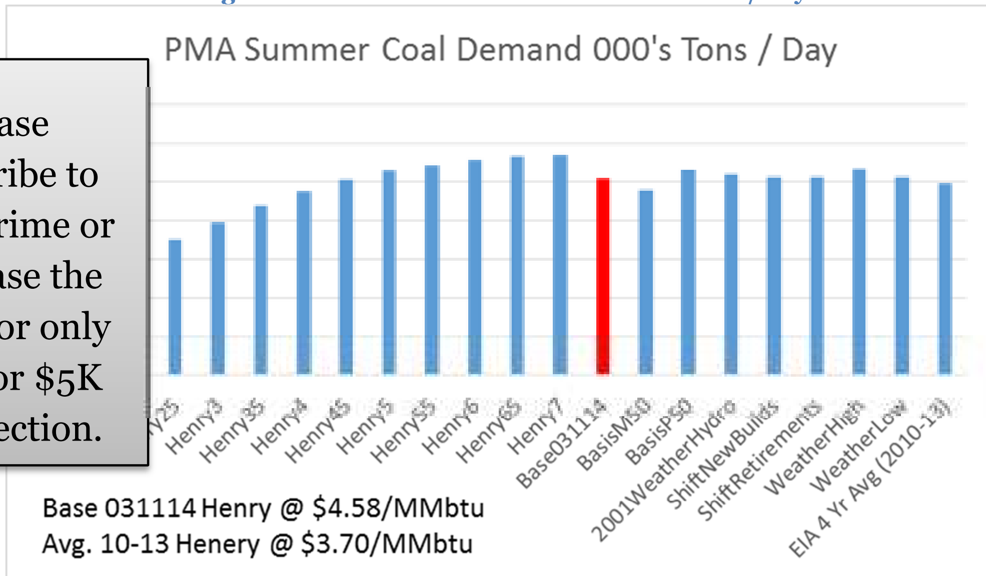

The price sensitivities show the increase in Henry Hub will lead to a rebound in coal demand relative to the four year average. Increase could be much higher if weather was more like the last four years vs. normal weather - See Figure 8. Coal demand is more dependent on basis changes than Henry changes. This is reasonable given much of the coal is in the Midwest which is seeing large basis spreads relative to the rest of the market. Retirements scheduled this year are not expected to impact the market. This shows again the major coal retirement impacts will not occur until the 2015-2016 period. Coal units being retired now are units that do not run significantly to begin with. The hydro issues are less impactful for coal than it is for gas, as most of the hydro is in the Western half of the US which only accounts for less than 10% of the total US coal fleet. Assuming gas and coal prices do not see a major change from the forward curve, the coal demand is range bound between 0 to 5% from the base case even if there are major weather changes.

A monthly view of demand is presented below in both Million MMbtu and kTons/day. The excel file is available for PMA subscribers.

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Figure 21 PMA Summer Coal Demand Million MMbtu Monthly

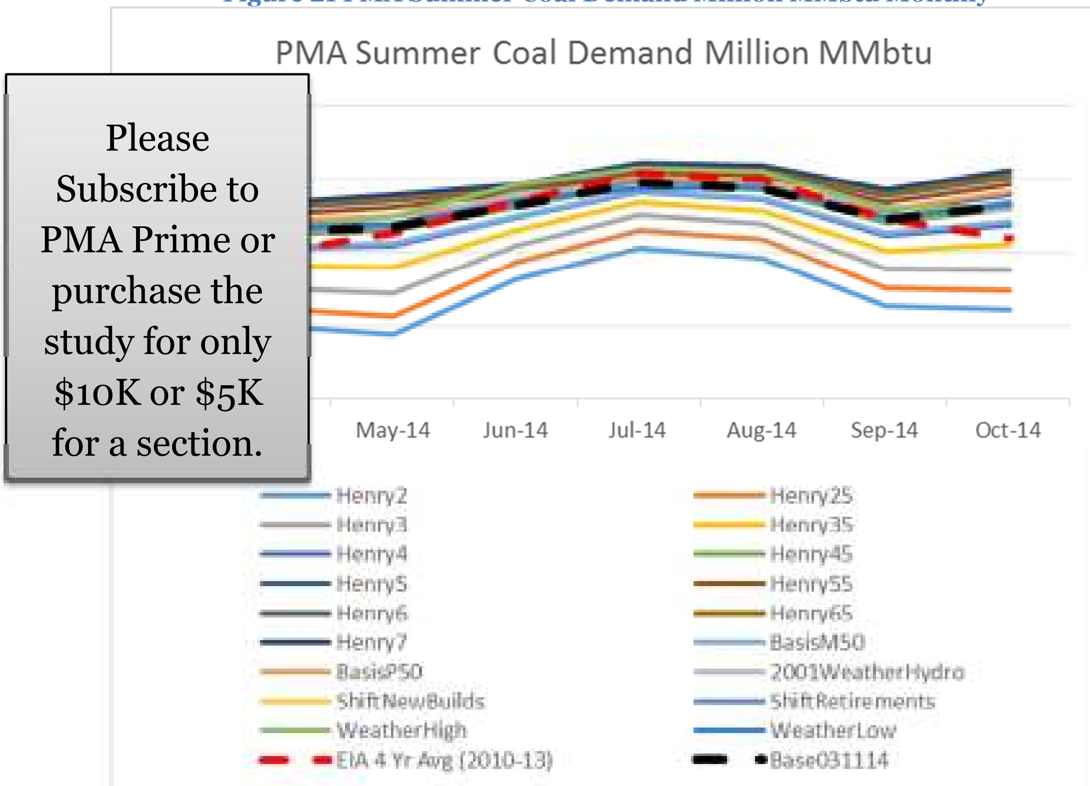

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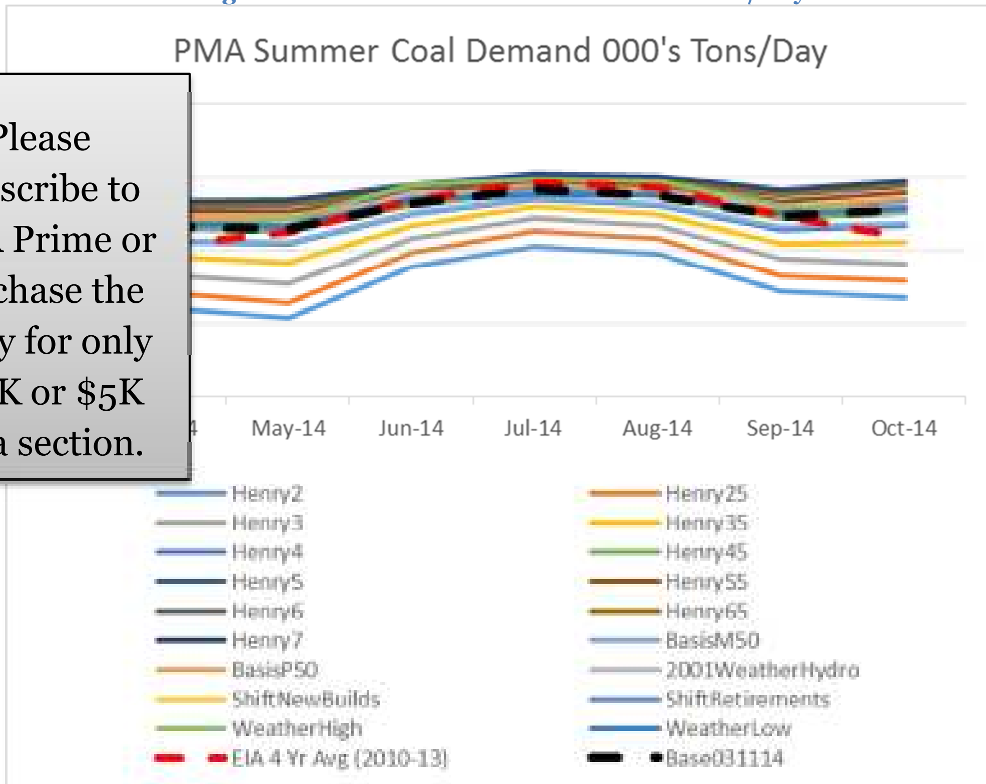
Figure 22 PMA Summer Coal Demand kTons/Day



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Power Prices

The following power prices represent the major trading areas across the country. More locations are available upon request. Validation graphs are available in the Appendix. In addition, subscribers to PMA can obtain excel files to compute their own calibration factors by month.

Nepool

Nepool is coming off a dramatic increase in prices given the extreme cold this winter which increased gas prices in the region over $25/MMbtu over Henry Hub price. The base case still has April basis at $10/MMbtu for the region.

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Figure 23 Nepool On-Peak Prices

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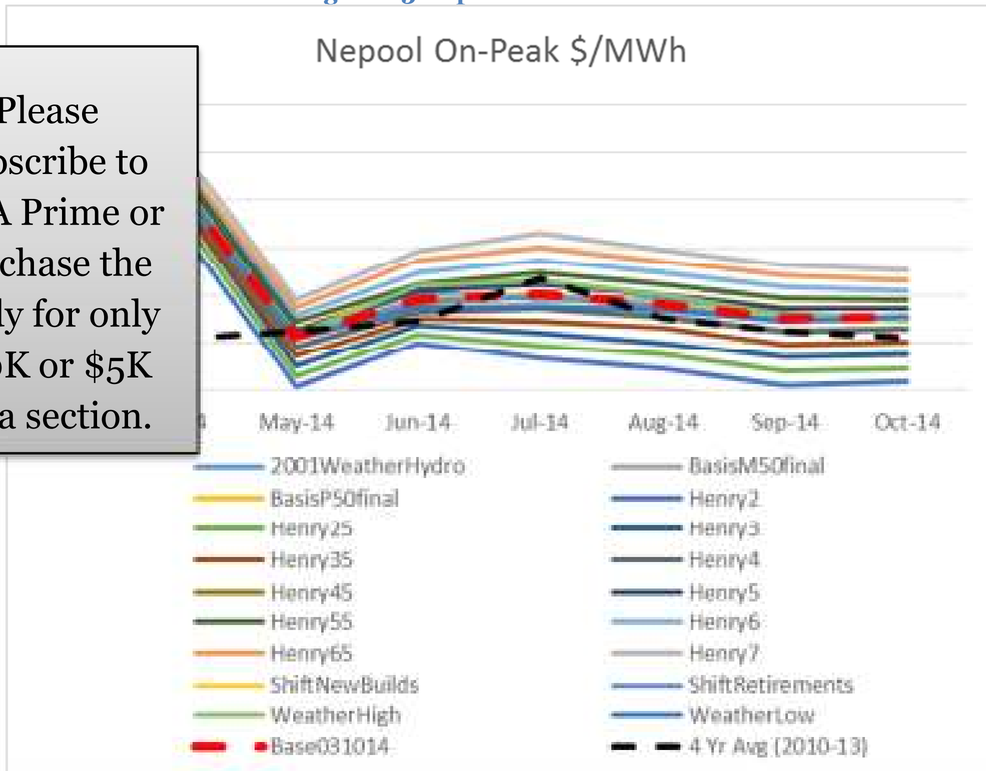

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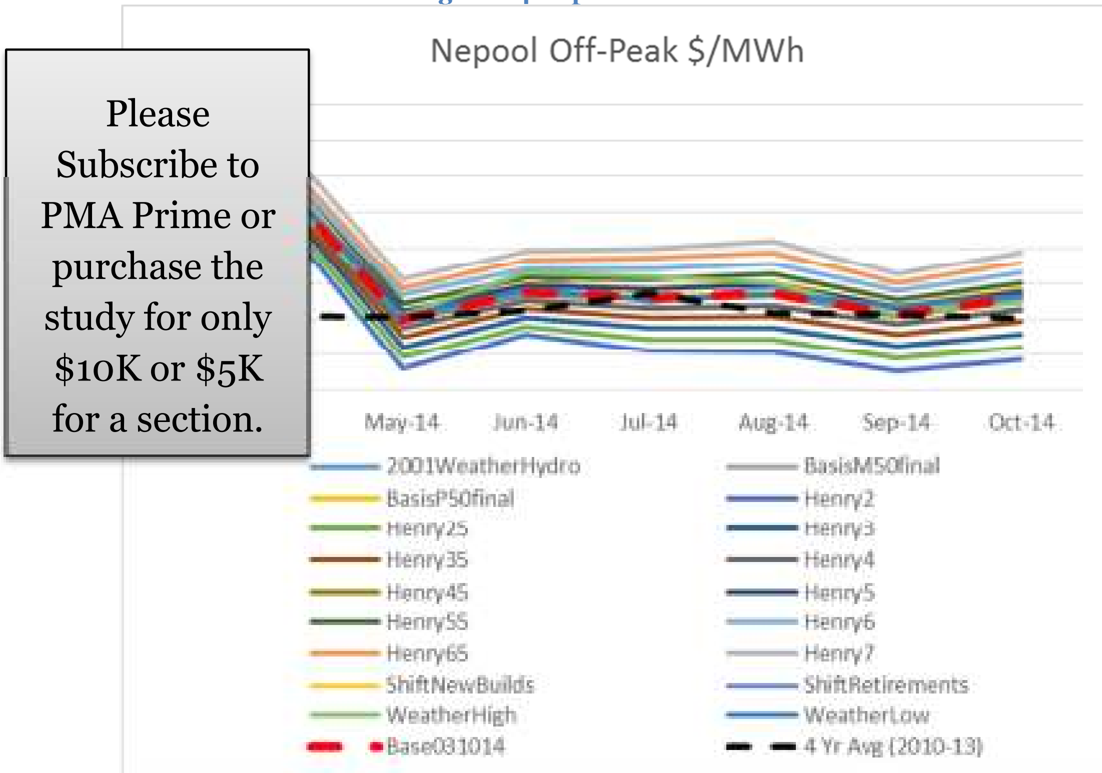
Figure 24 Nepool Off-Peak Prices



Nepool prices are quite linear to gas prices as seen in Figure 25.

Figure 25 Nepool On-Peak Prices vs. Henry Hub

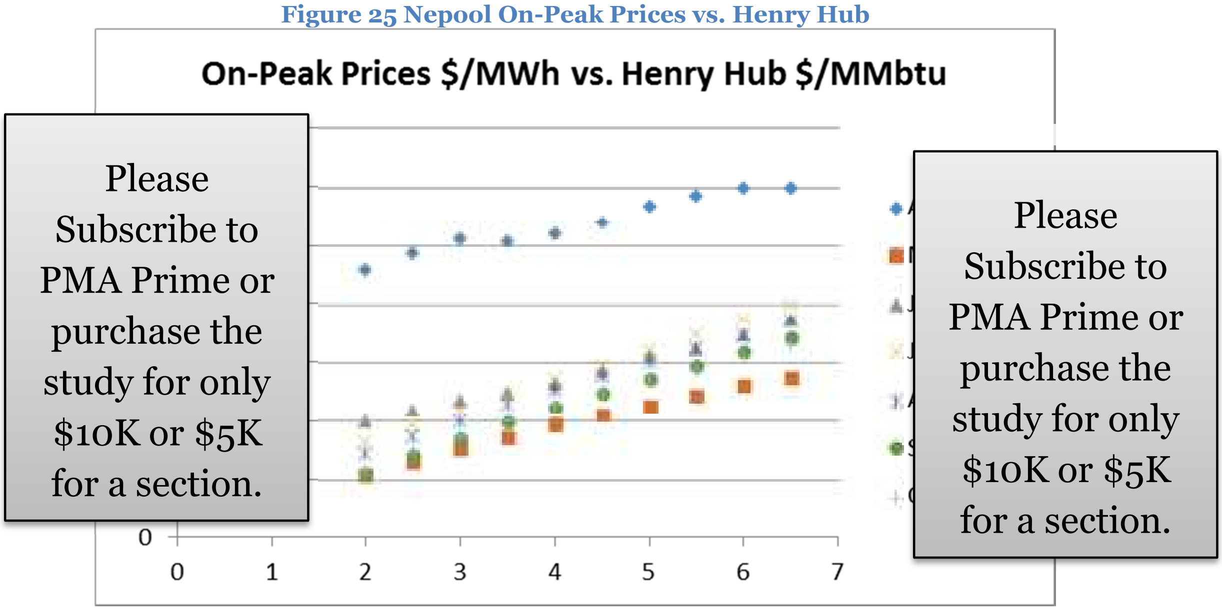


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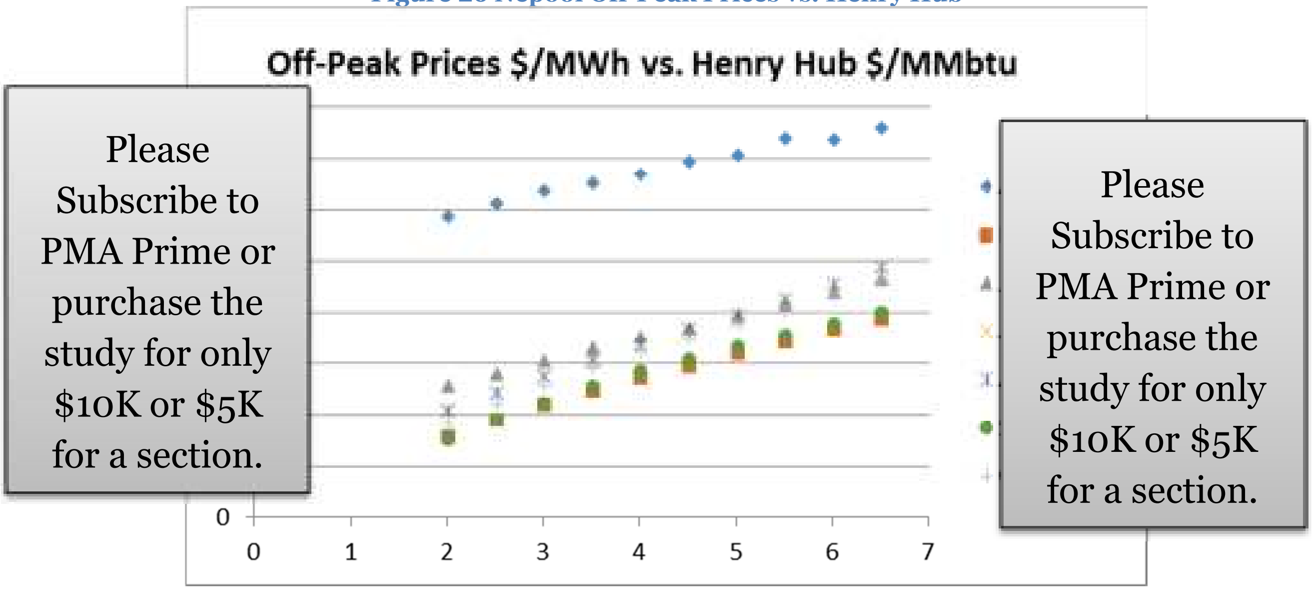
Figure 26 Nepool Off-Peak Prices vs. Henry Hub



New York Zone J

New York Zone J is susceptible to price blow outs given the limited generation internally and the constraints into the region.

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Figure 27 NY Zone J On-Peak Prices

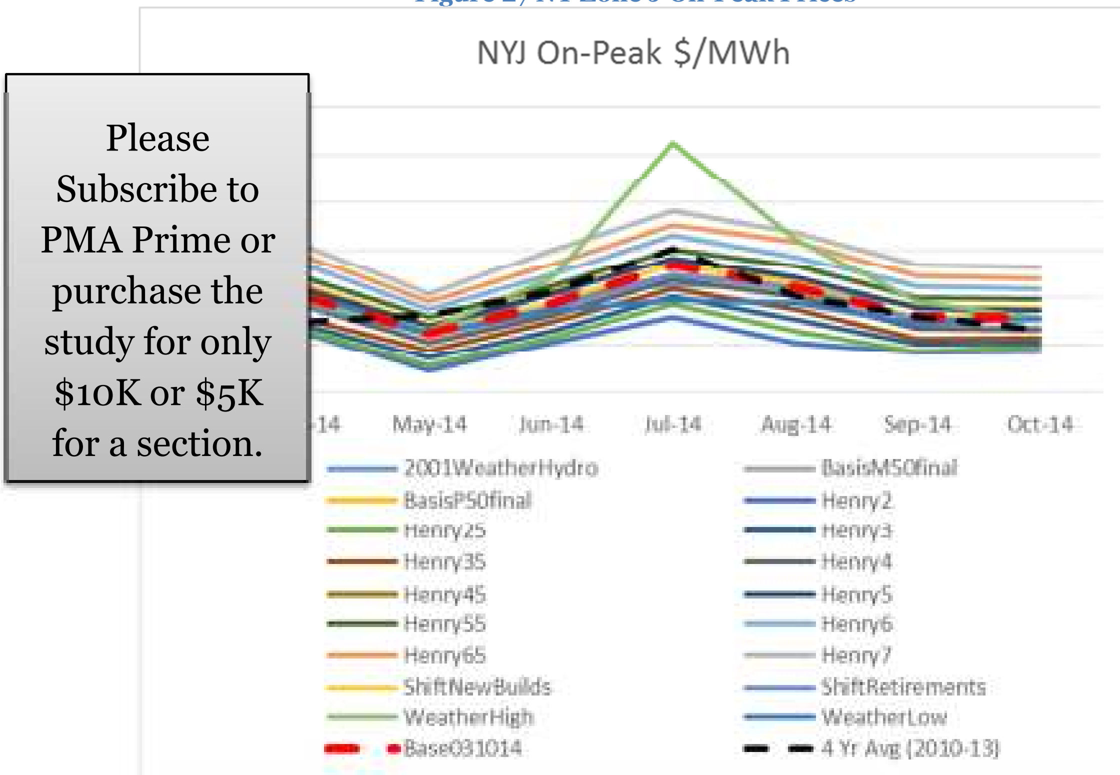

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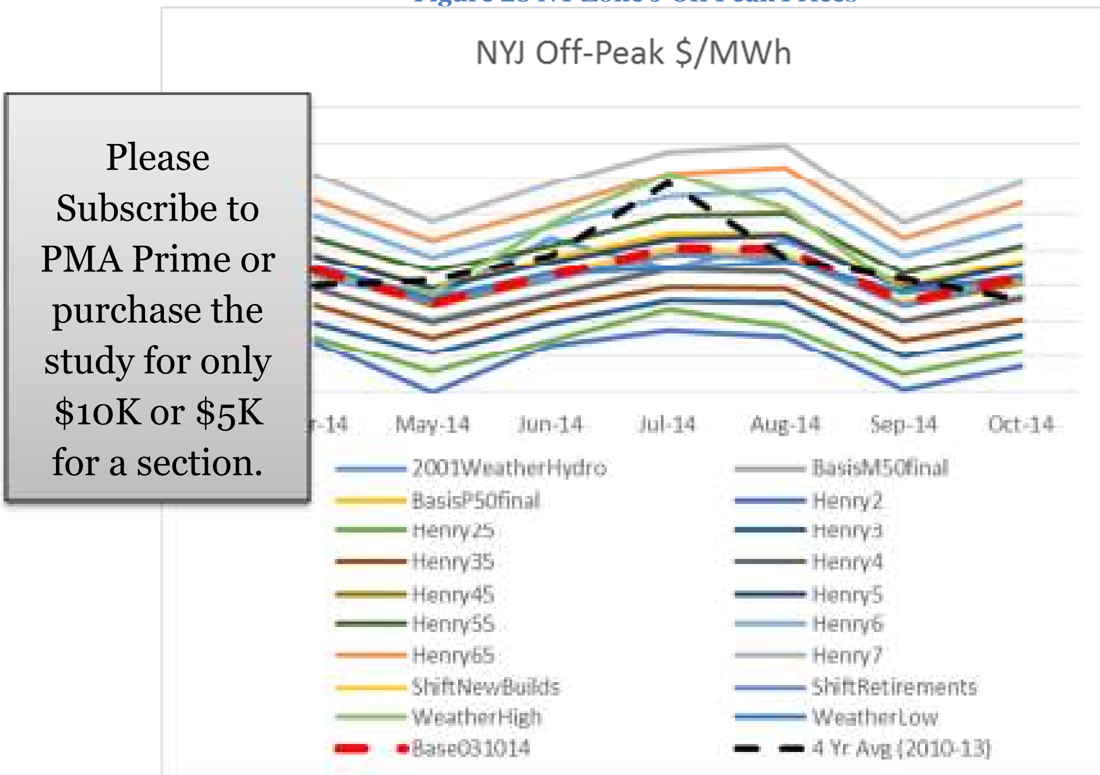
Figure 28 NY Zone J Off Peak Prices



NY Zone J On-peak is less linear than off-peak showing more of an exponential curve as gas prices rise.

Figure 29 NY Zone J On-Peak Price vs Henry Hub

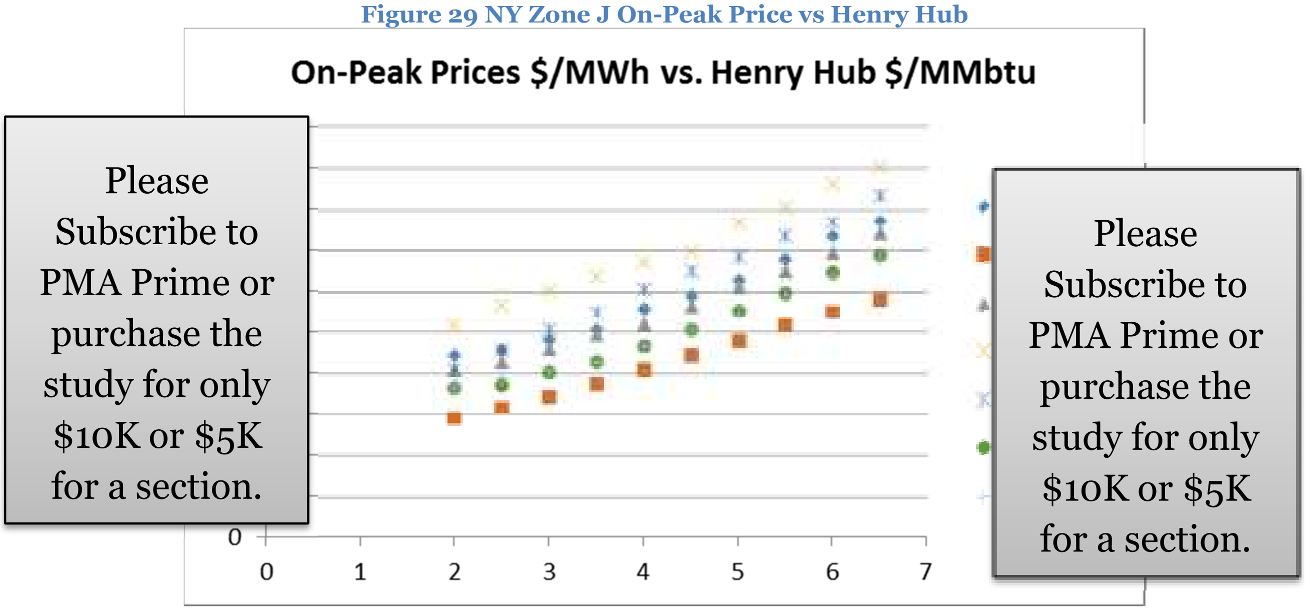


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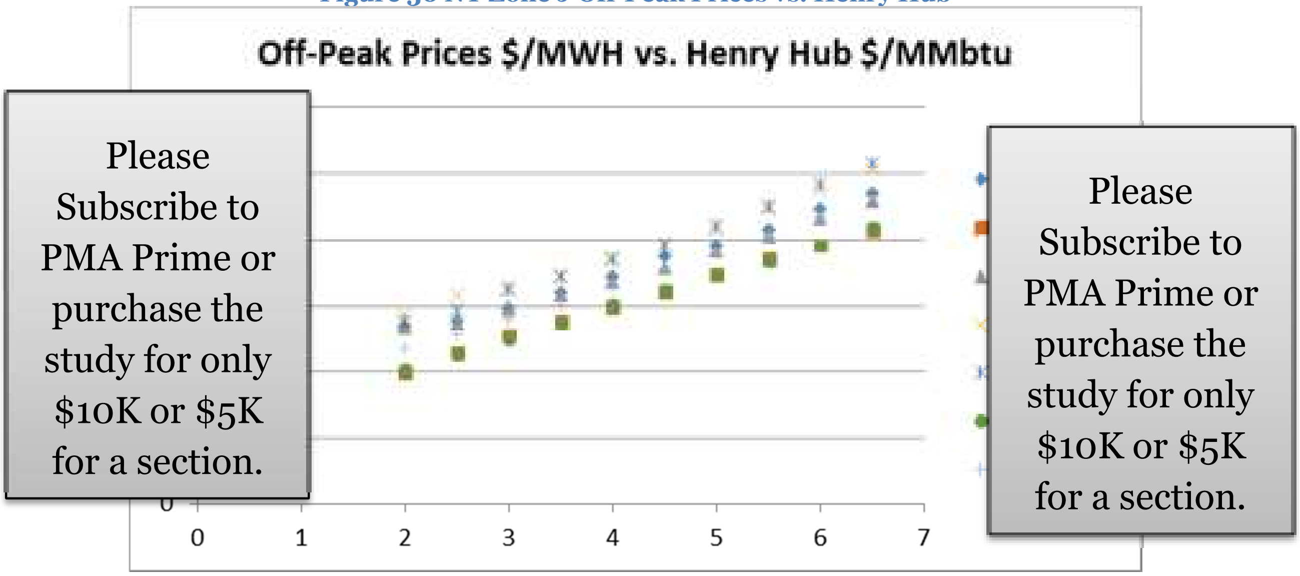
Figure 30 NY Zone J Off-Peak Prices vs. Henry Hub



PJM-West

PJM-West can be pulled up by the issues occurring in the Northeast. Weather can swing prices $63/MWh in July.

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Figure 31 PJM-West On-Peak Prices

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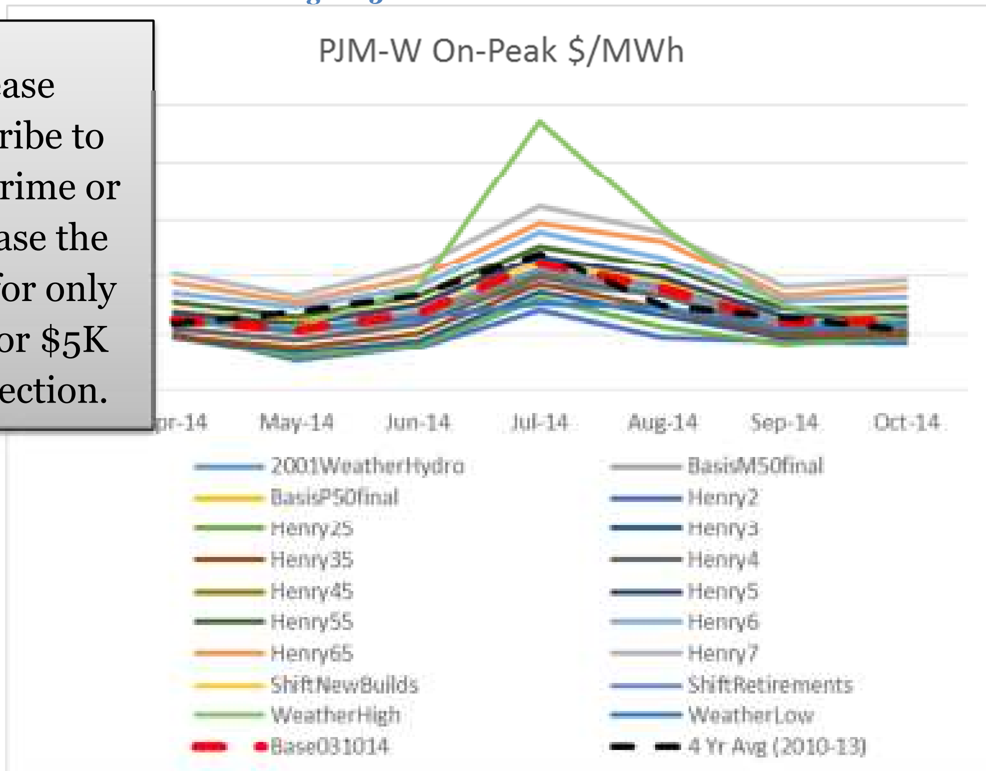

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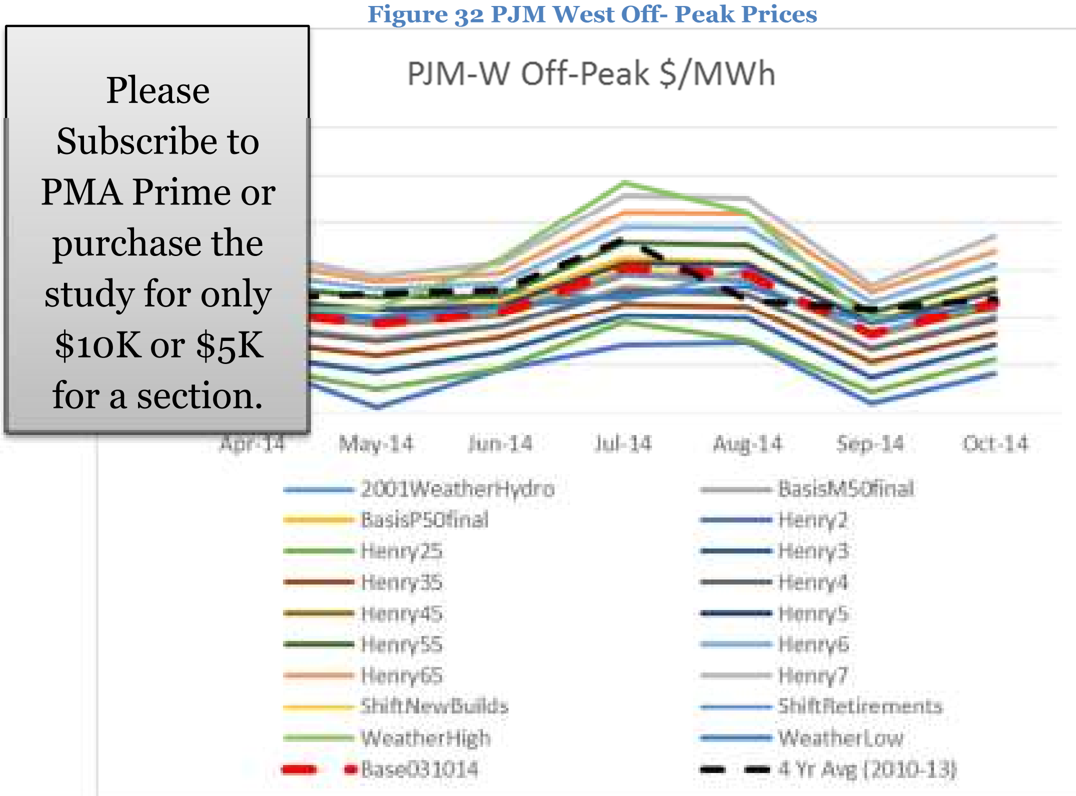
Figure 32 PJM West Off- Peak Prices



PJM-West prices do flatten out as gas prices goes down in certain months.

Figure 33 PJM West On-Peak Prices vs. Henry Hub

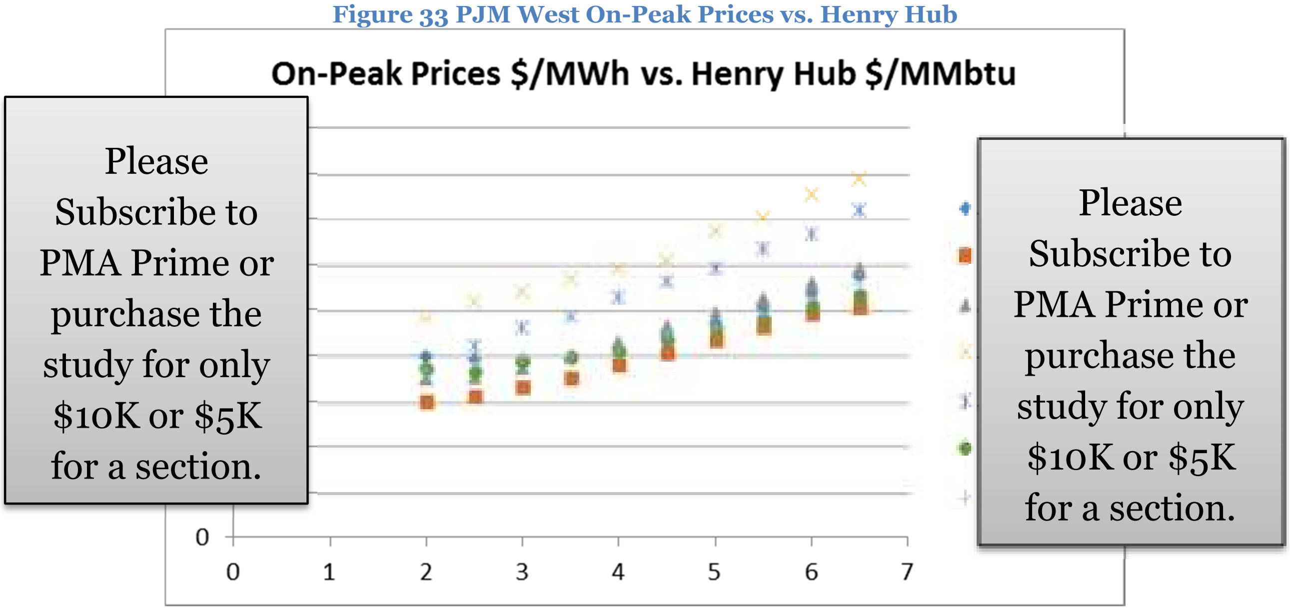


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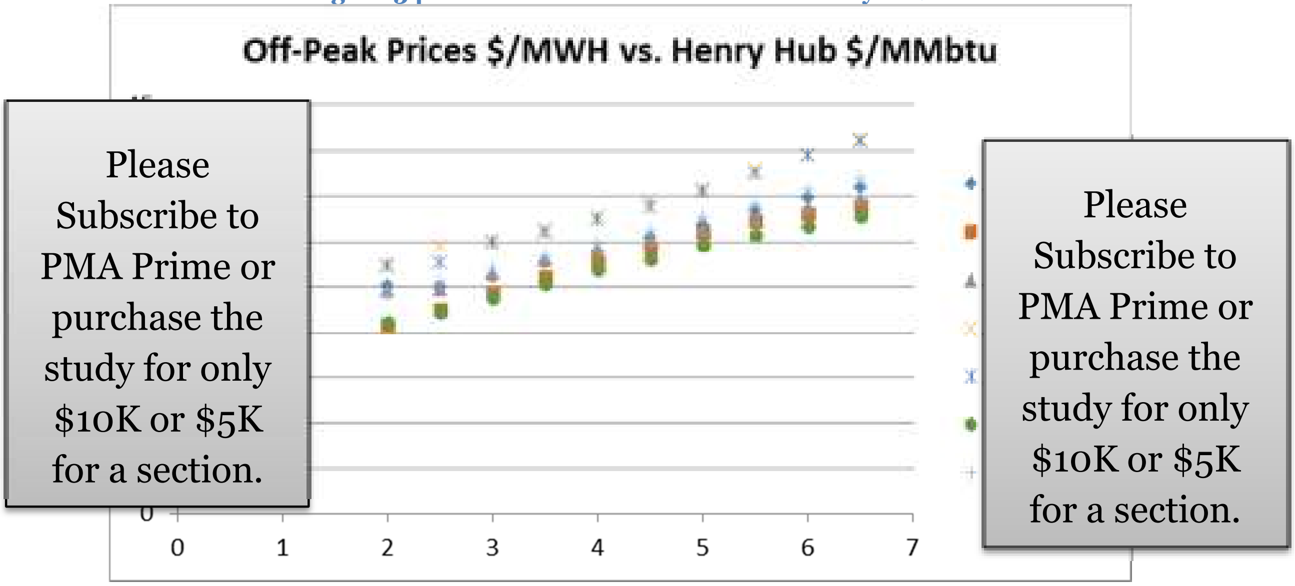
Figure 34 PJM West Off-Peak Prices vs. Henry Hub



AD-Hub

Given the AD-Hub large dependence on coal, the region is less sensitive to gas price swings. Off-peak prices in the region can get quite low as many large coal units minimum capacity are quite high.

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Figure 35 AD-Hub On-Peak Prices

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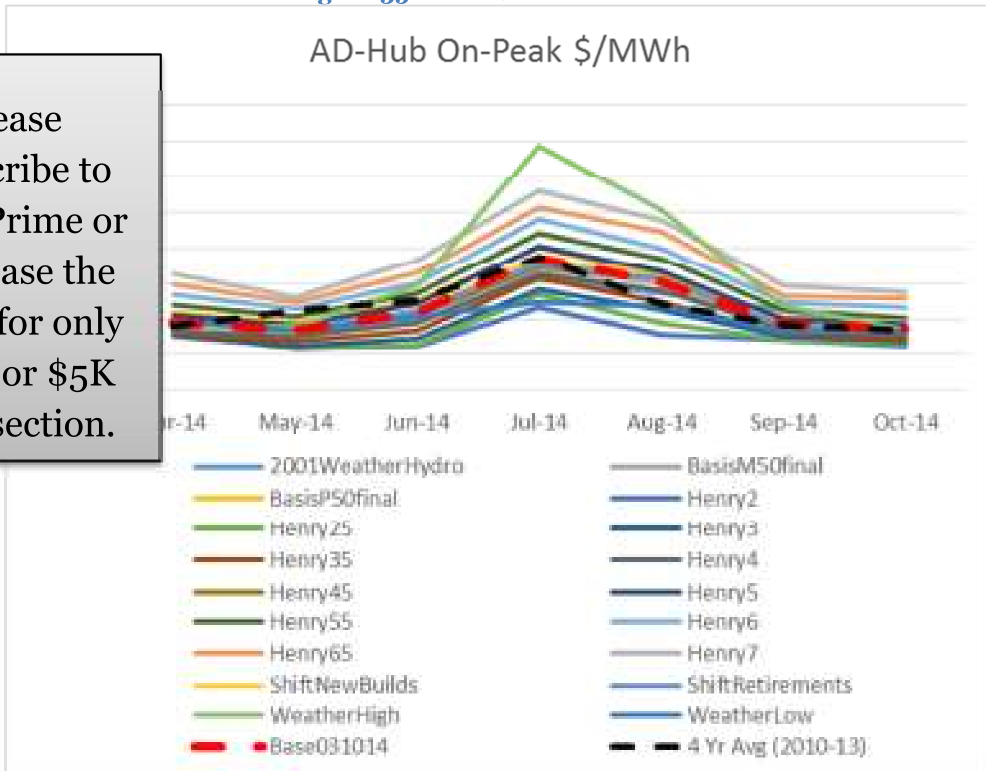

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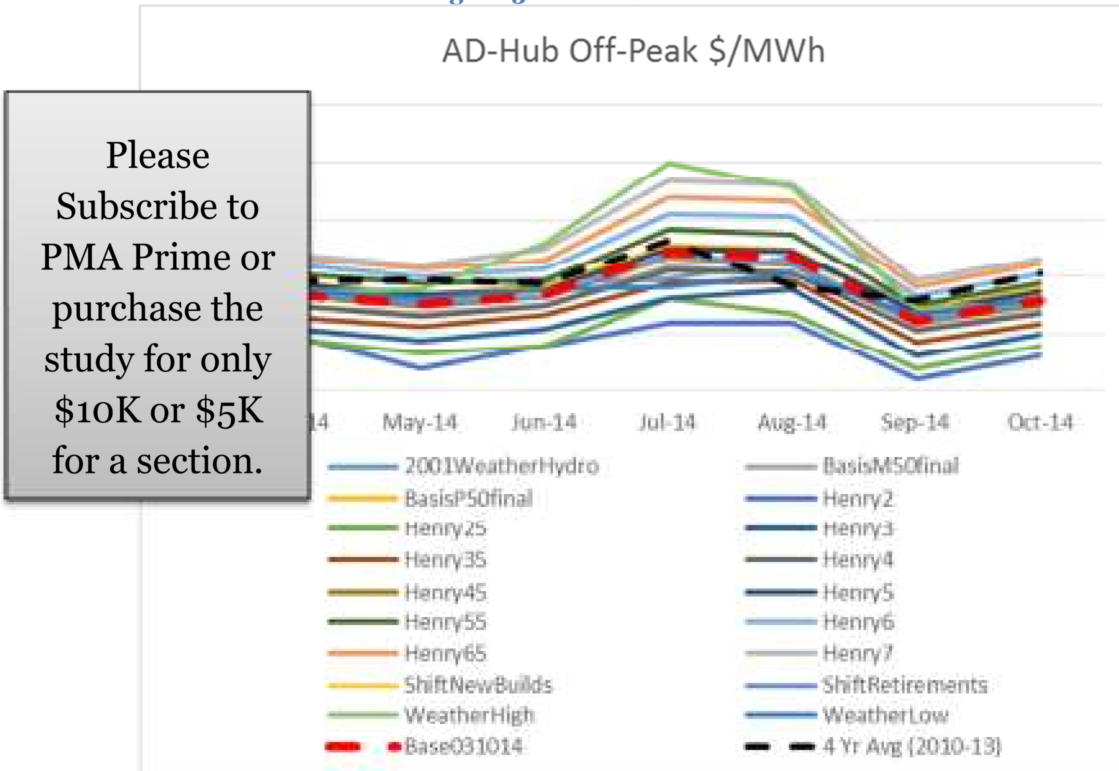
Figure 36 AD-Hub Off-Peak Prices



AD-Hub given its large coal generators result in a very flat price curve as gas prices fall in non-peak months.

Figure 37 AD-Hub On-Peak Prices vs. Henry Hub

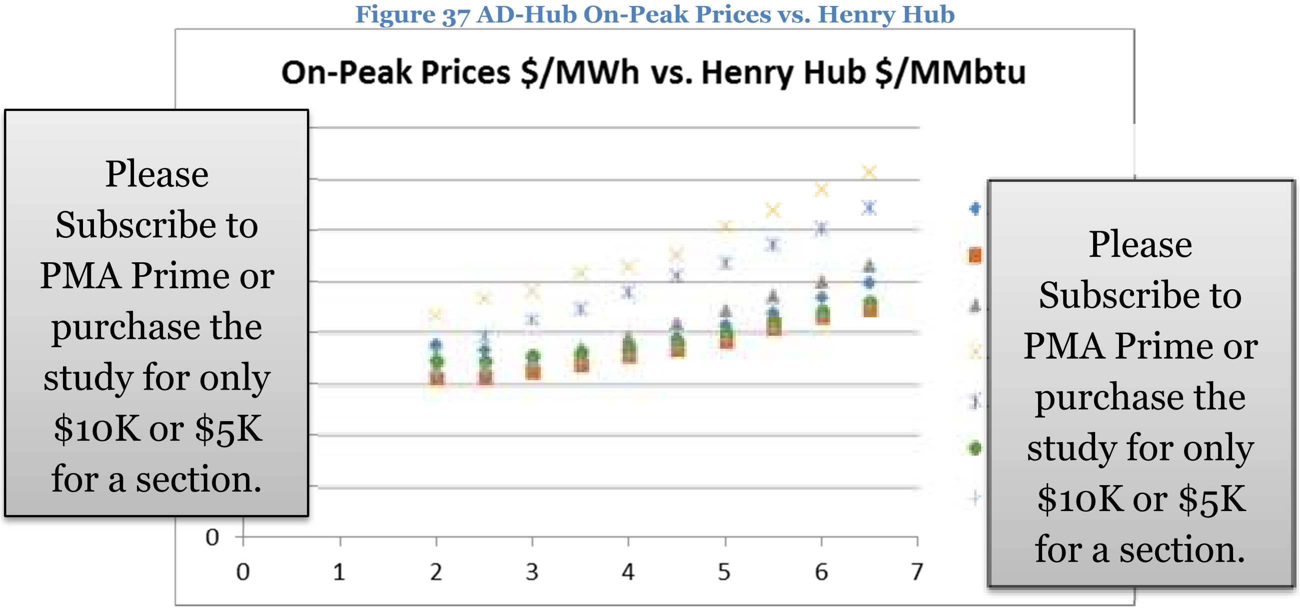


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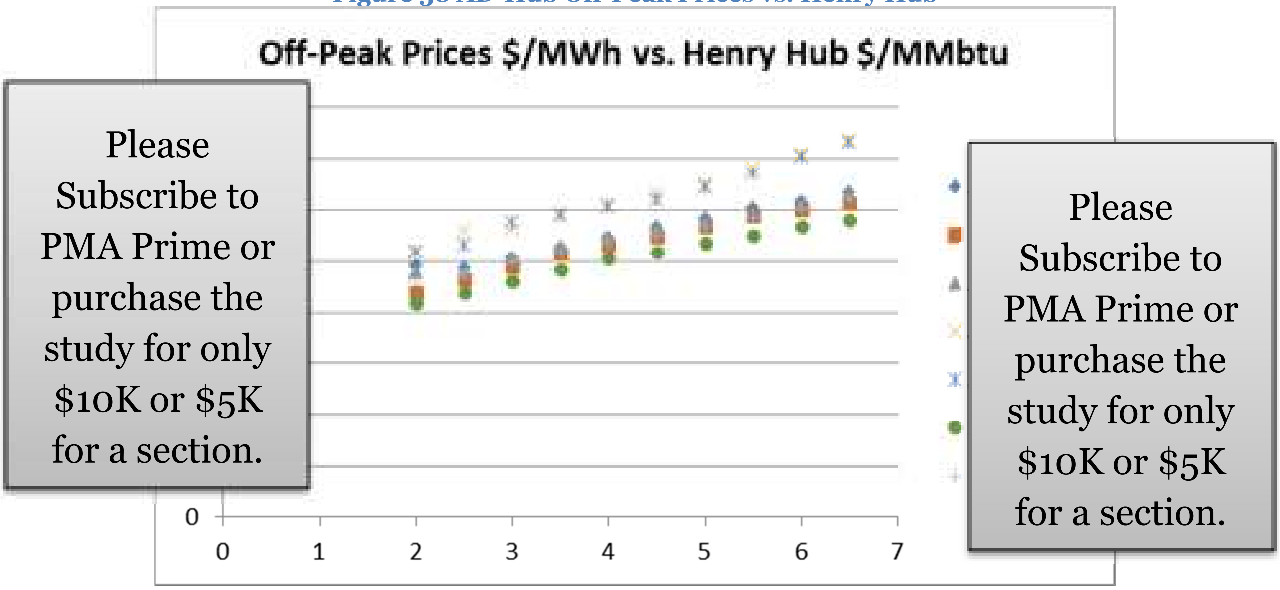
Figure 38 AD-Hub Off-Peak Prices vs. Henry Hub



ERCOT-Houston

ERCOT, in general, is very susceptible to price blow outs as the market is designed as an energy only market. Over the past few years, ERCOT has limited the power prices caps resulted in a slowdown in investment. ERCOT is having large load growths relative to the rest of country. A hot summer can cause an unstable market with significant price rises.

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Figure 39 ERCOT-Houston On-Peak Prices

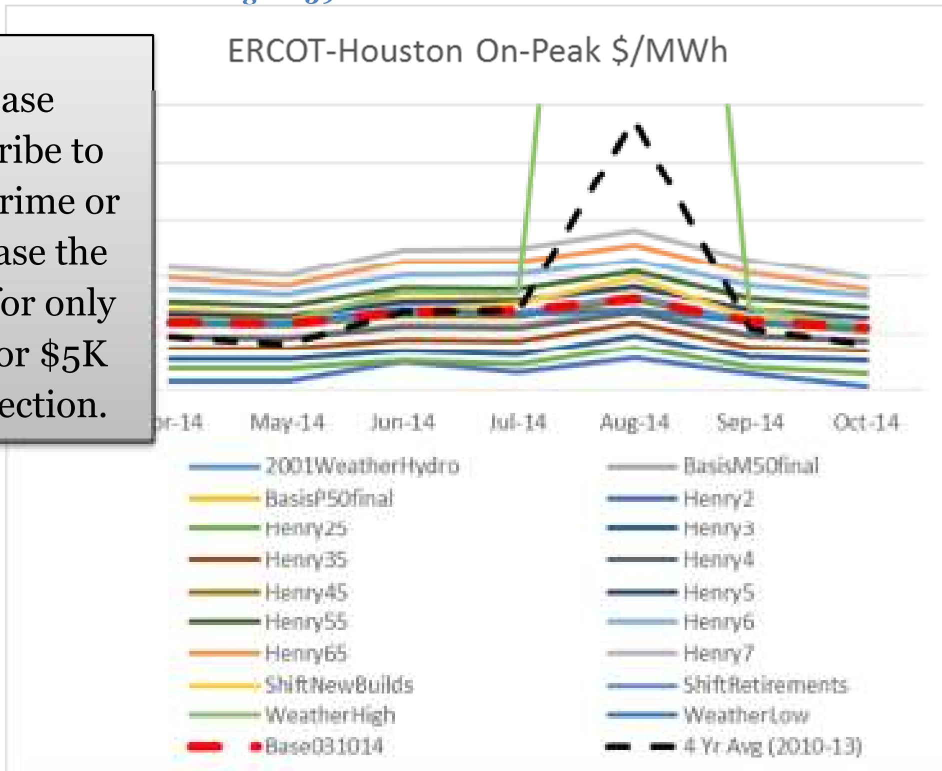

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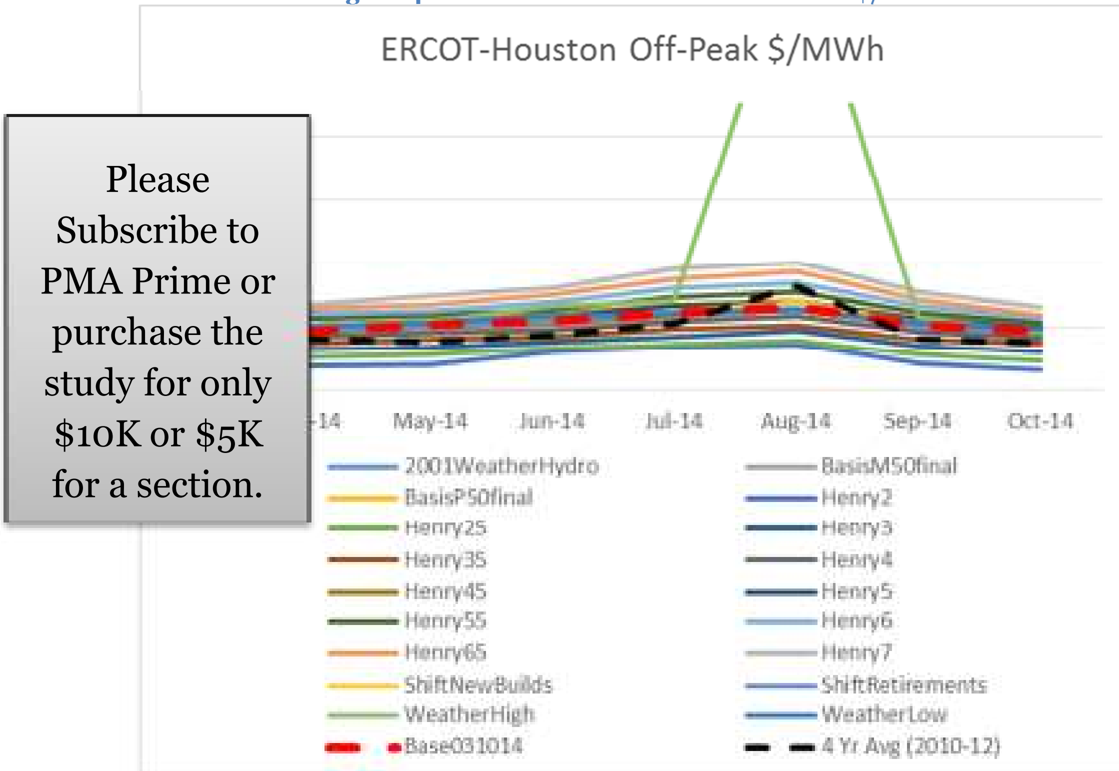
Figure 40 ERCOT-Houston Off-Peak Prices $/MWh



ERCOT large dependence makes the power price and Henry Hub price very linear.

Figure 41 ERCOT-Houston On-Peak Prices vs. Henry Hub

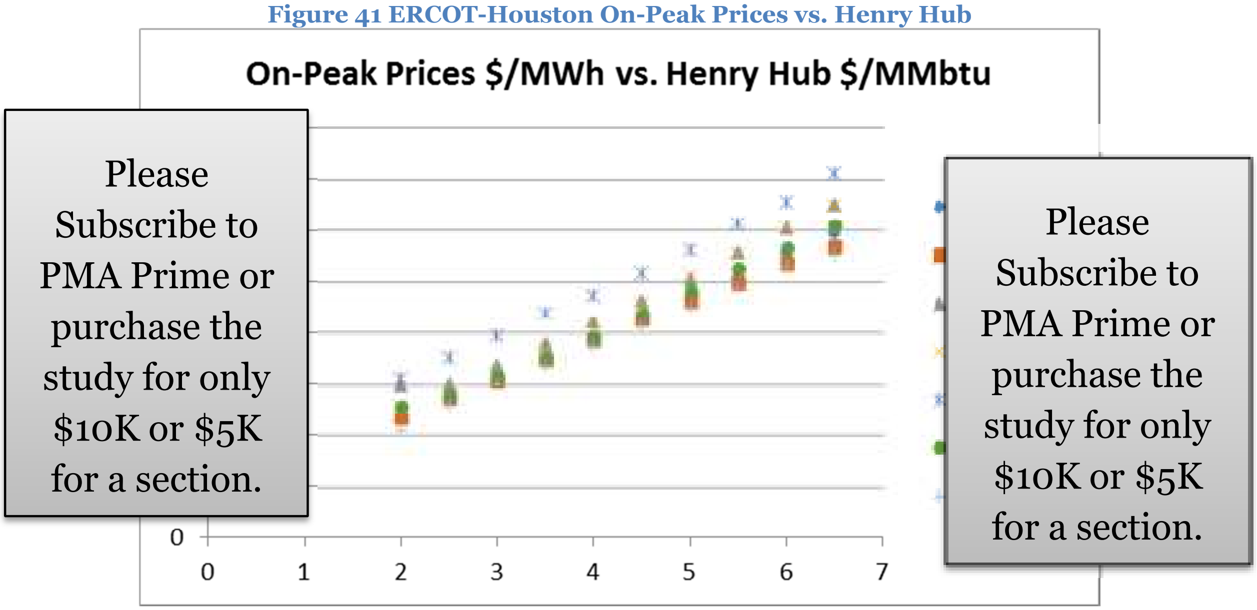


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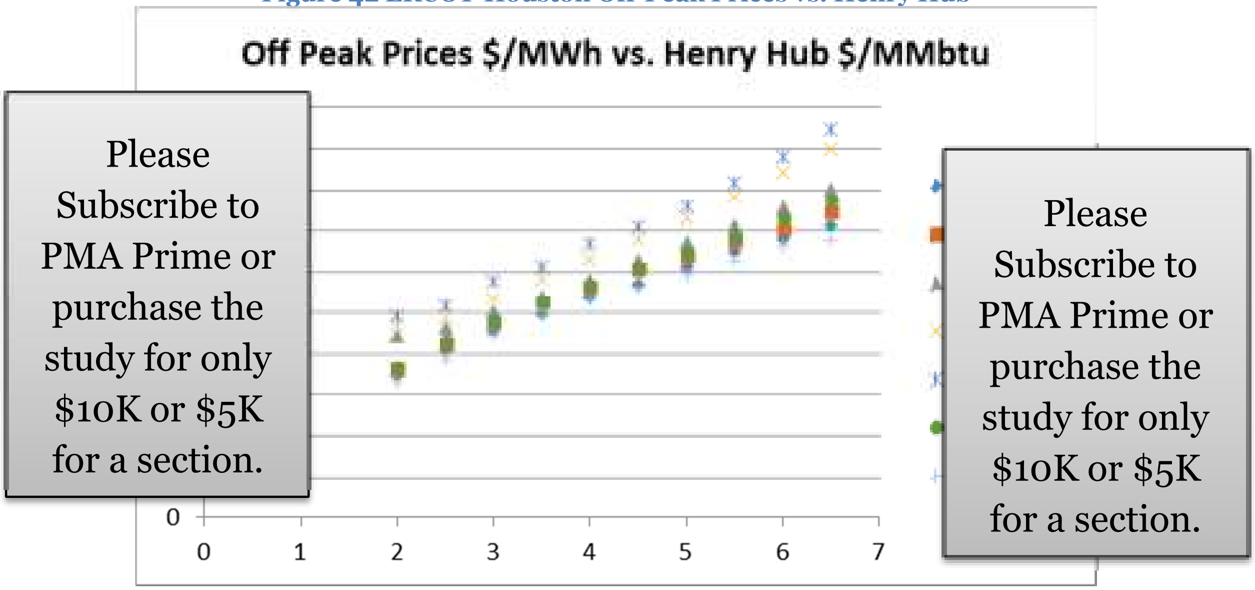
Figure 42 ERCOT-Houston Off-Peak Prices vs. Henry Hub



Four Corners

The region has had a big swing in off-peak prices. Compared to the previous regions Four Corners is less susceptible to the hot weather.

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Figure 43 Four Corners On-Peak Prices

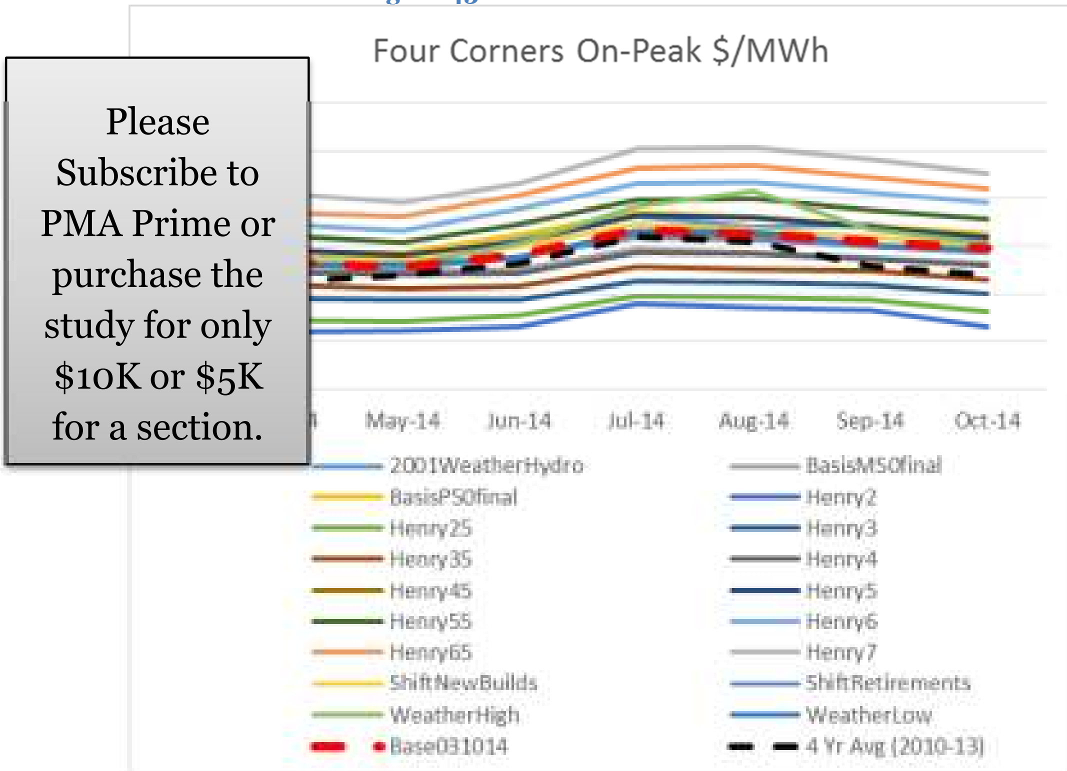

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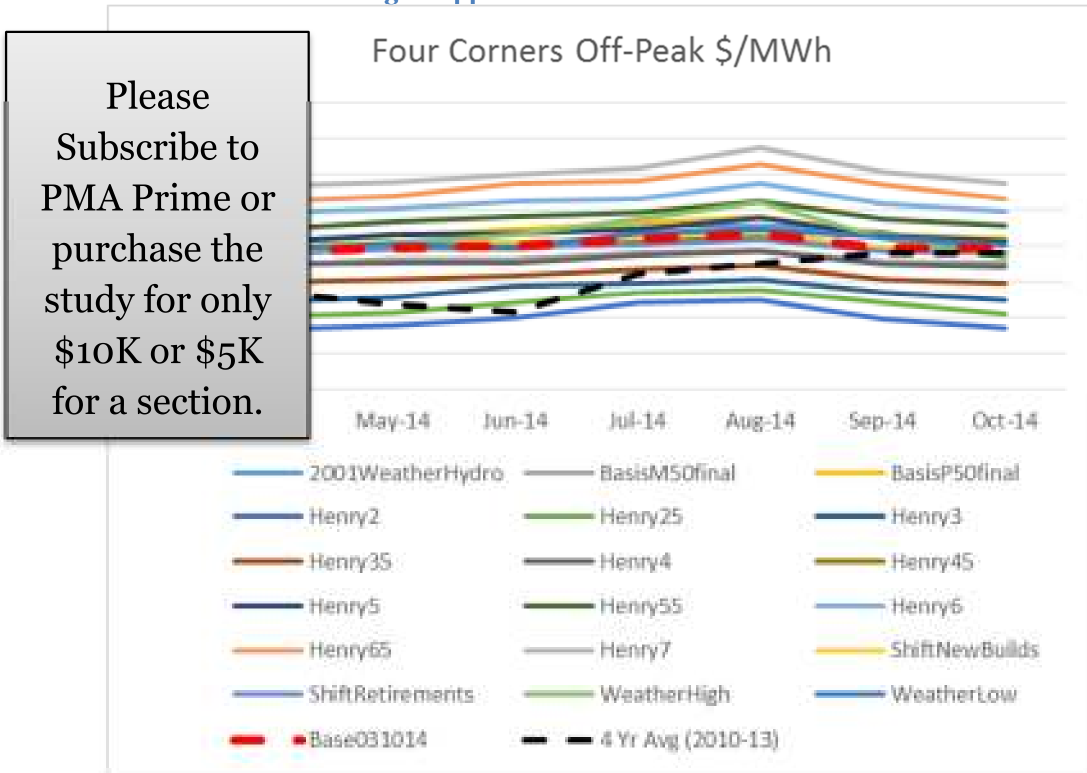
Figure 44 Four Corners Off-Peak Prices



Four Corners power prices are linear with Henry Hub prices.

Figure 45 Four Corners On-Peak Prices vs. Henry Hub

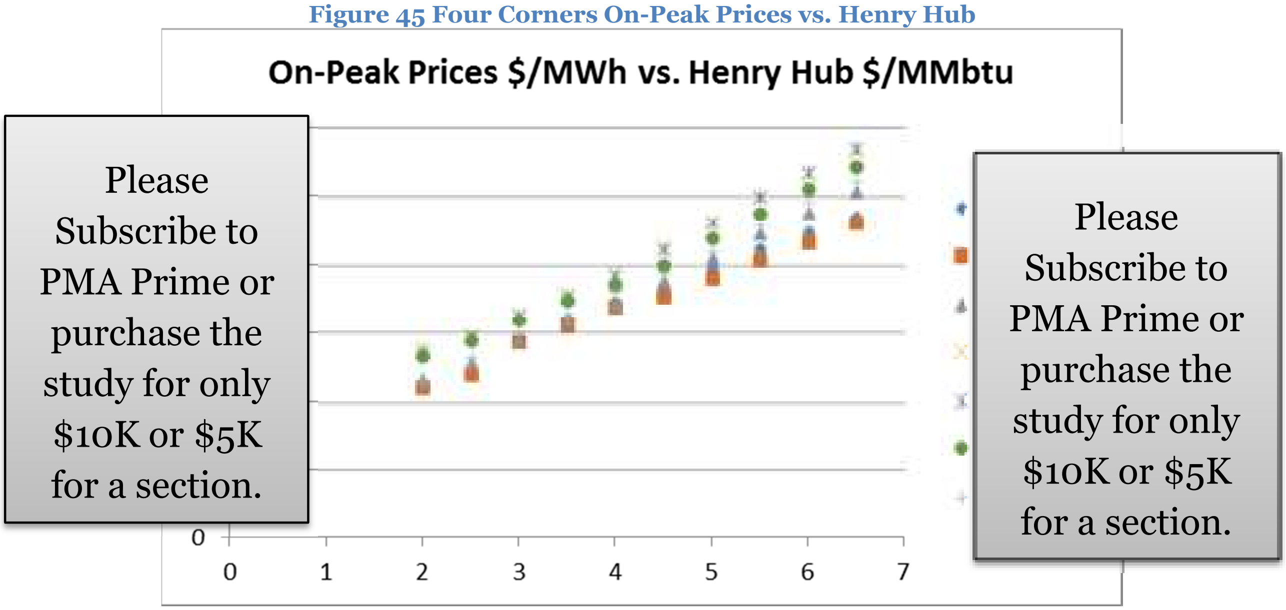


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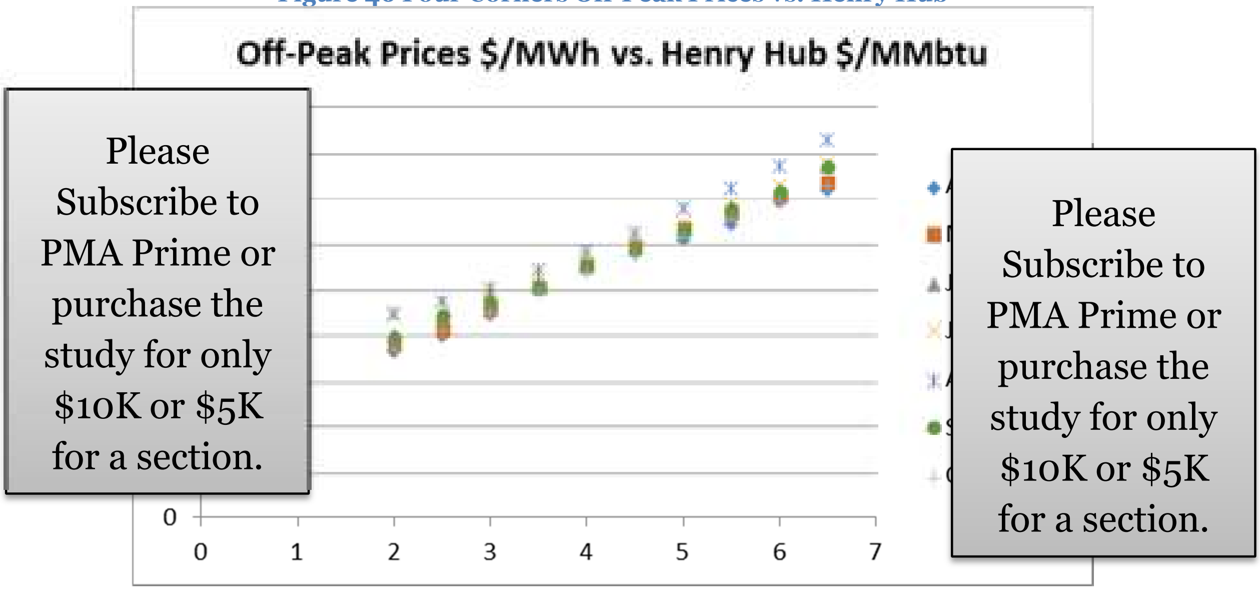
Figure 46 Four Corners Off-Peak Prices vs. Henry Hub



Palo Verde

The region will be impacted by the drought in the West. If the hydro and weather is similar to 2001, an increase of $5/MWh is likely assuming ideal transmission. A concern not modeled is the restriction of fossil and nuclear units as water levels become low for plant operations.

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Figure 47 Palo Verde On-Peak Prices

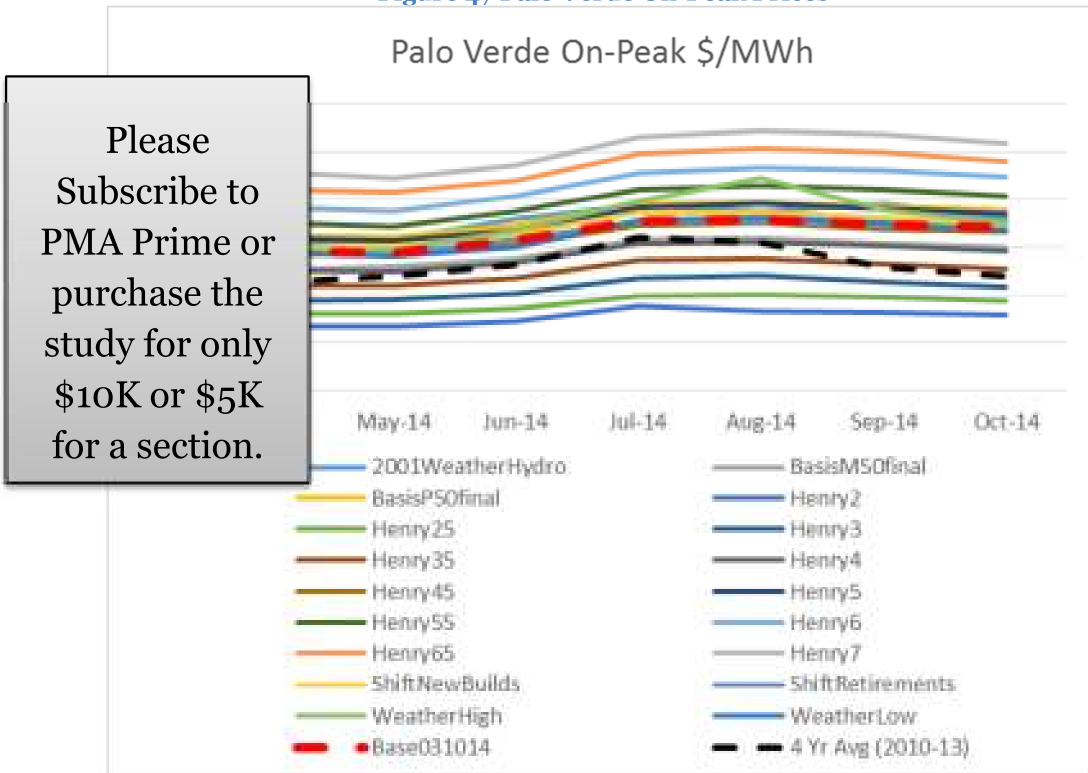

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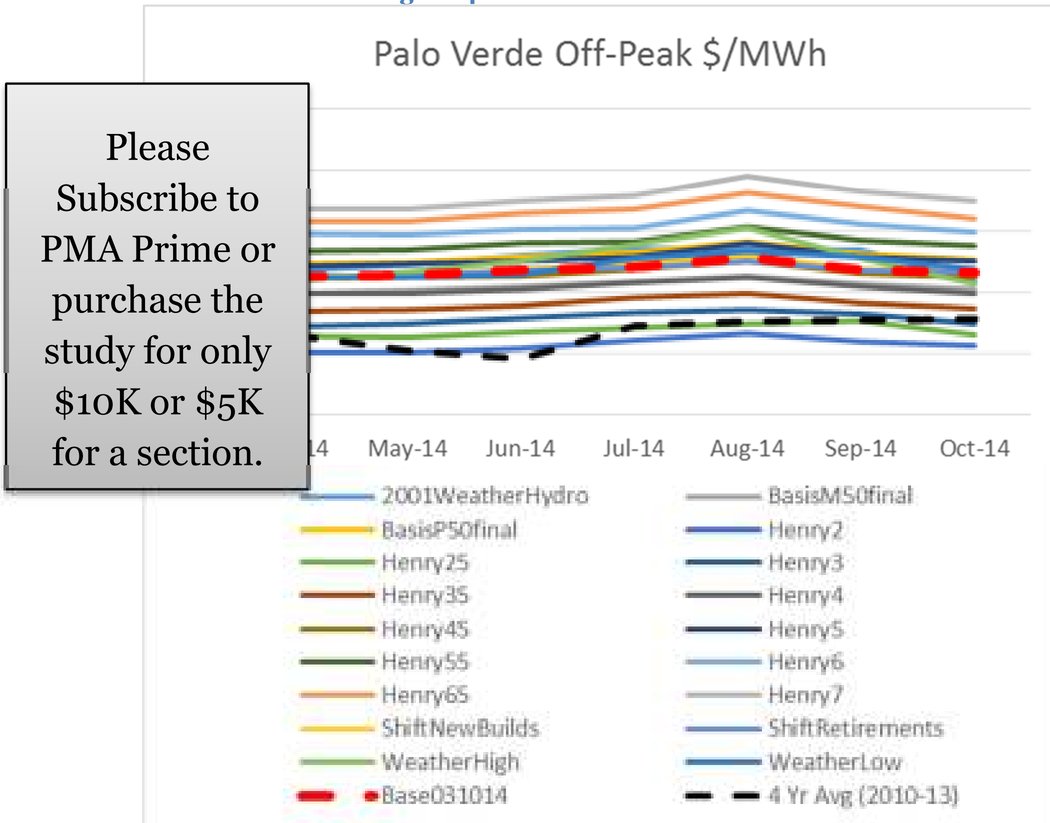
Figure 48 Palo Verde Off-Peak Prices



Palo Verde power prices have a very linear relationship with Henry Hub.

Figure 49 Palo Verde On-Peak Prices vs. Henry Hub

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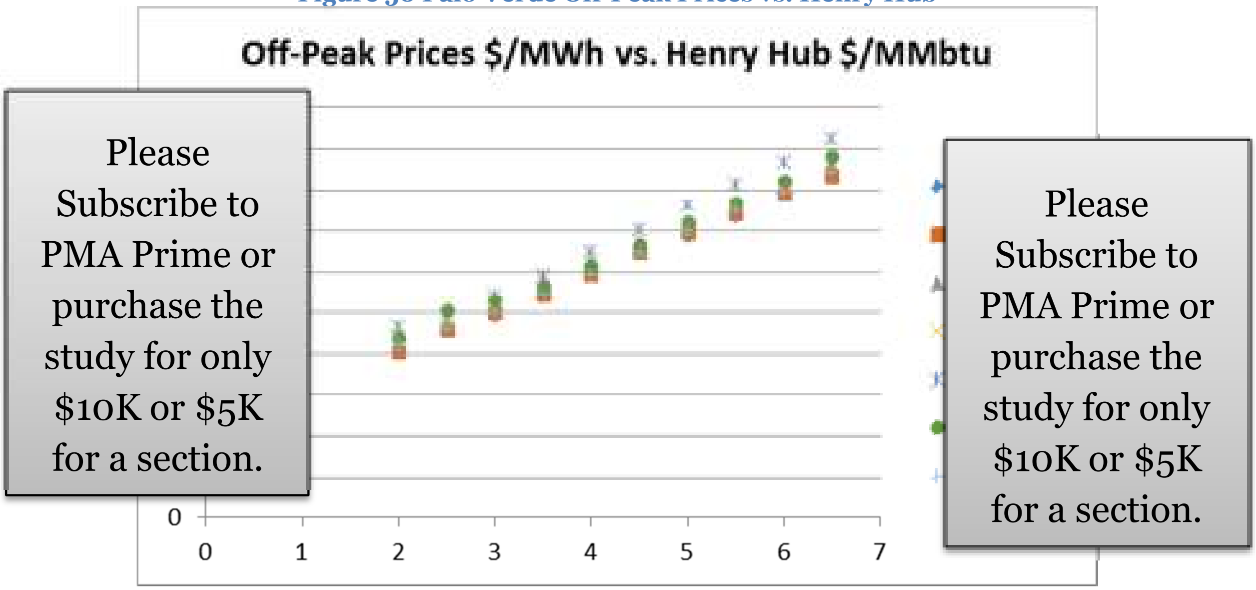
Figure 50 Palo Verde Off-Peak Prices vs. Henry Hub



Mid-Columbia

Mid-Columbia will be the most impacted by a change in hydro conditions. The highest price sensitivity in June and July is from the 2001 hydro and weather condition vs. the $7/MMbtu sensitivity.

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Figure 51 Mid-Columbia On-Peak Prices

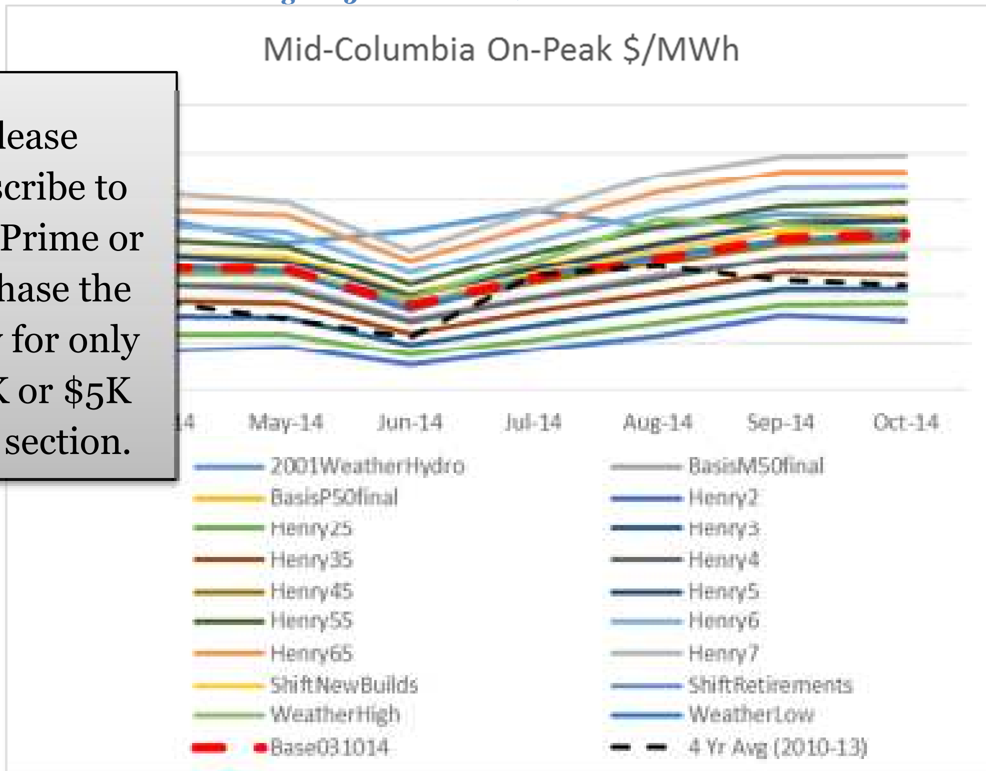

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Figure 52 Mid-Columbia Off-Peak Prices

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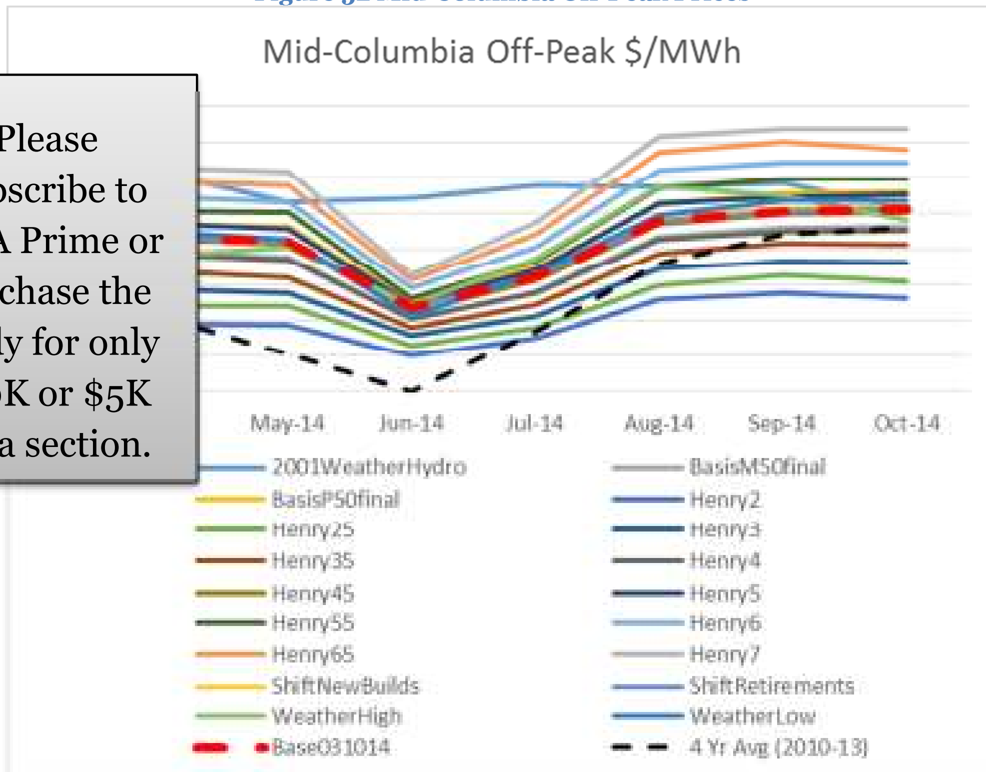

Mid-Columbia prices relative to Henry Hub is showing a linear relationship. There are some large differences in slope between various months.

Figure 53 Mid-Columbia On-Peak Prices vs. Henry Hub

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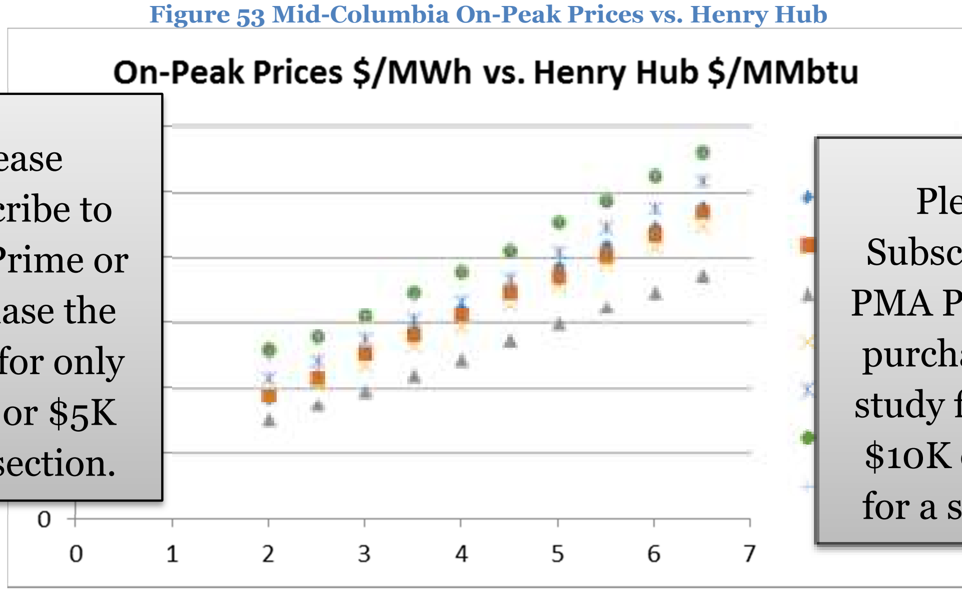

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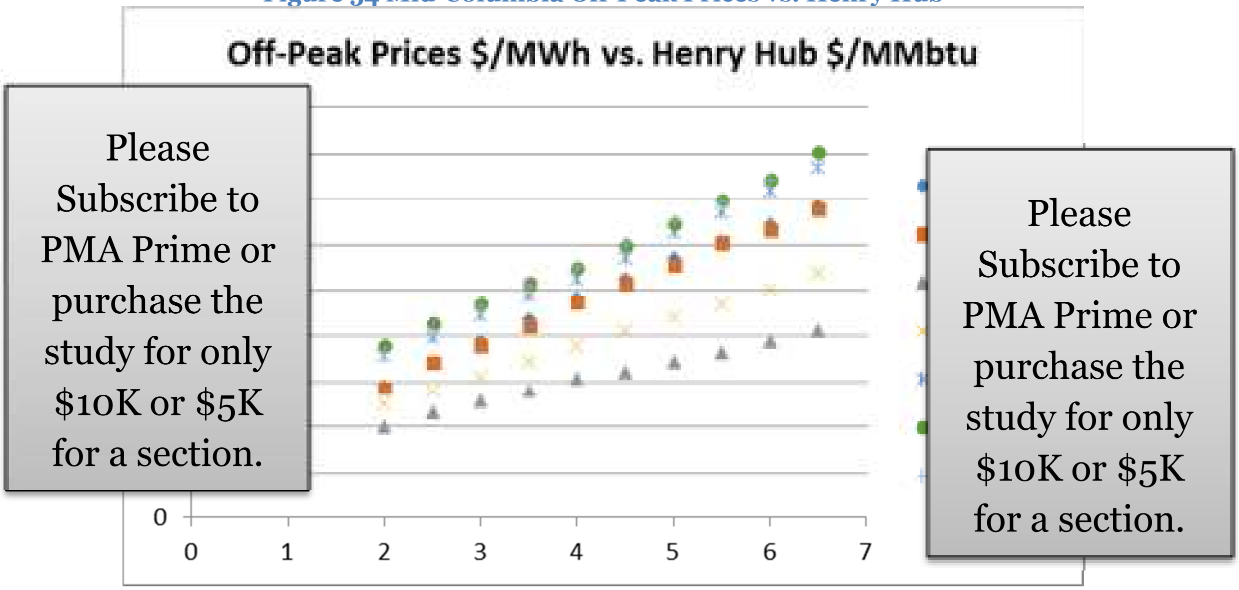
Figure 54 Mid-Columbia Off-Peak Prices vs. Henry Hub



Company Performance

Presented below are the top 10 utilities by size of generation portfolio in the US and how their generation portfolio performed assuming an un-hedge merchant portfolio. Other companies are available for request. Given the uncertainty in business operations, such as hedging and plant bidding, PMA can only give a proxy of impact. The unit listing and percentage profile is available for subscribers to PMA. In no way is PMA giving investment advice, since many times a generation fleet performance is only one piece of the business.

The below figure ranks each companies impact to their generation fleet profitability relative to the base case depending on the sensitivity.

Low Gas Sensitivity

NRG and AEP fleet will likely be the most impacted if gas prices were to go below $4/MMbtu. Calpine actually performs better with lower natural gas prices.

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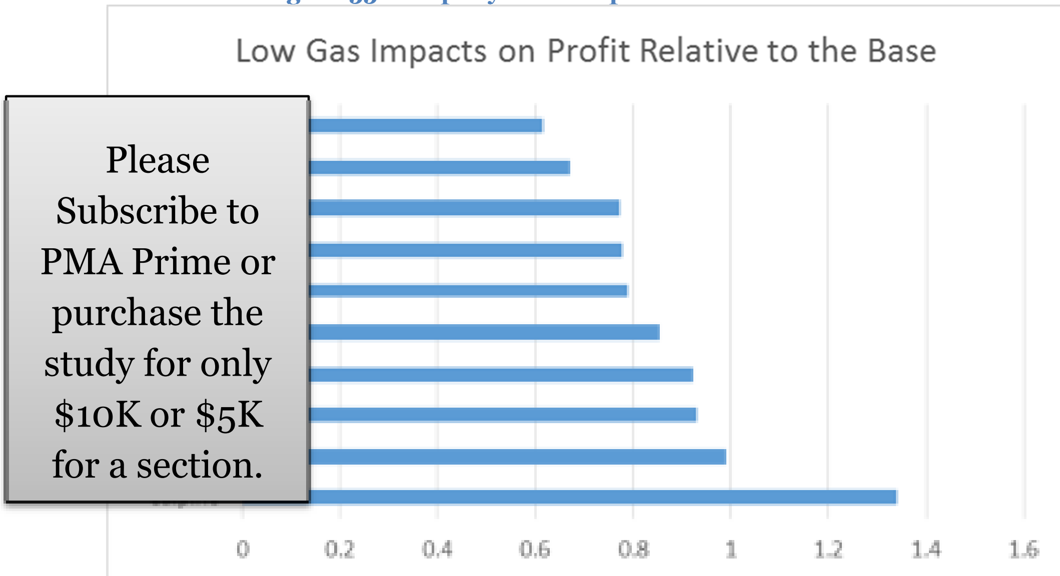
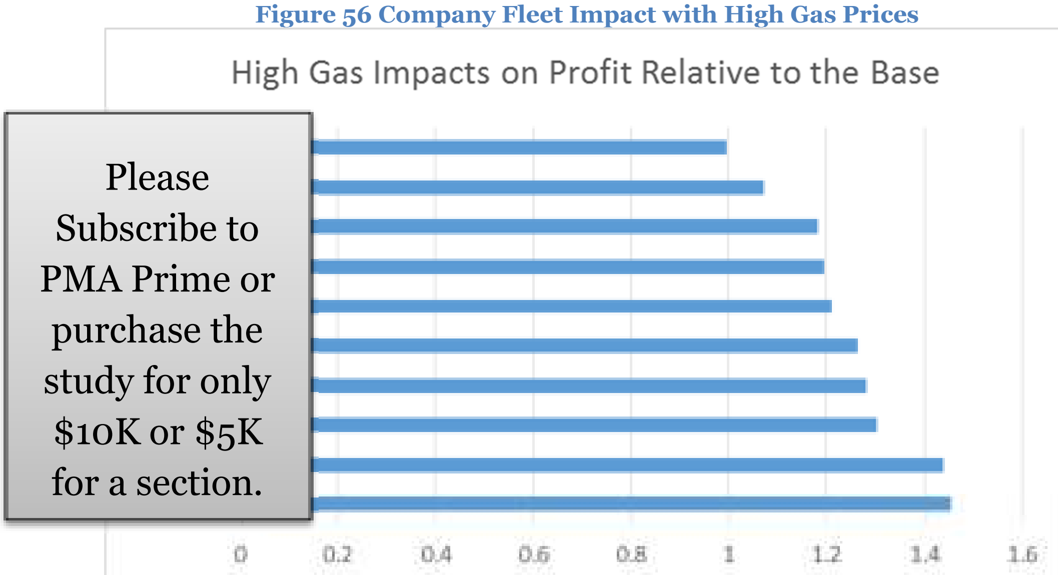
Figure 55 Company Fleet Impact with Low Gas Prices



High Gas Sensitivity

Calpine shows the largest drop from the base case if gas prices continues to rise. AEP and NRG benefit the most. AEP and NRG upside is greater than the downside, but this is assuming the odds of going to $7/MMbtu and $2/MMbtu is the same.

Figure 56 Company Fleet Impact with High Gas Prices



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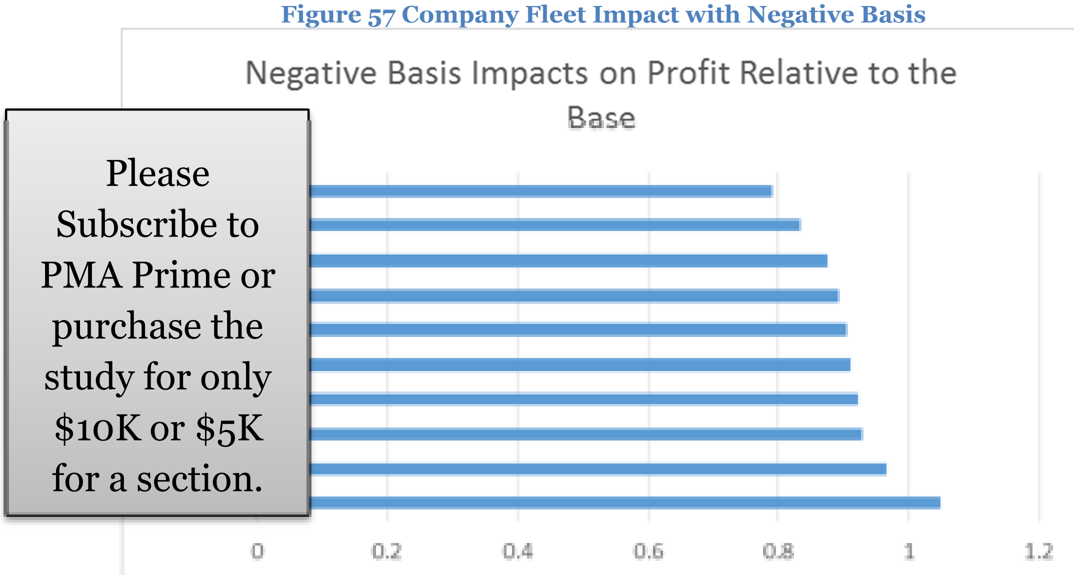
Negative Basis Sensitivity

NRG and AEP can see some significant loss relative to the base case if basis was going to drop by $0.50/MMbtu. Calpine improves in greater negative basis spreads.

Figure 57 Company Fleet Impact with Negative Basis



Positive Basis Sensitivity

Every company benefits if basis would move up $0.50/MMbtu other than Calpine. AEP and NRG will experience the most upside.

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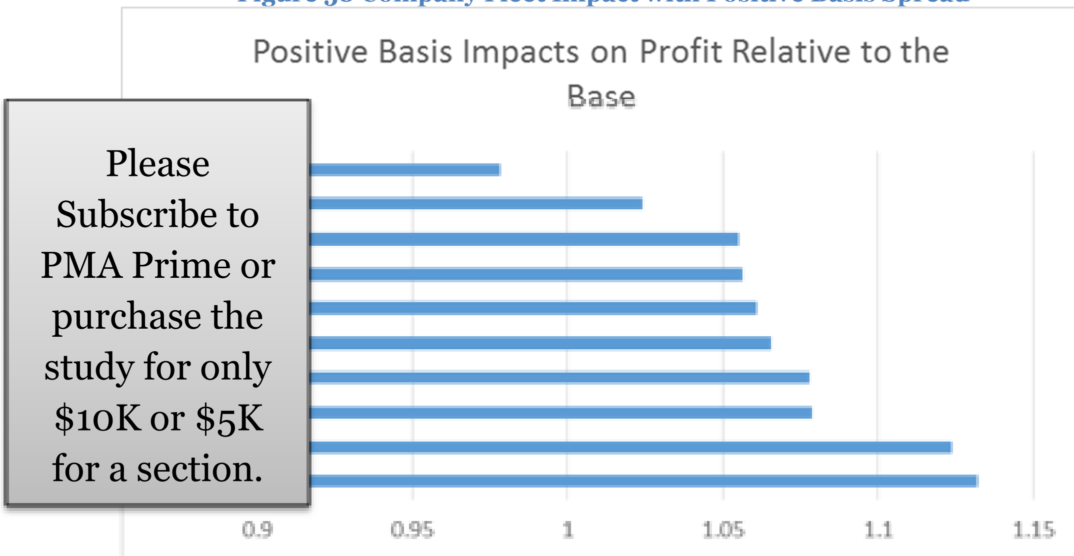
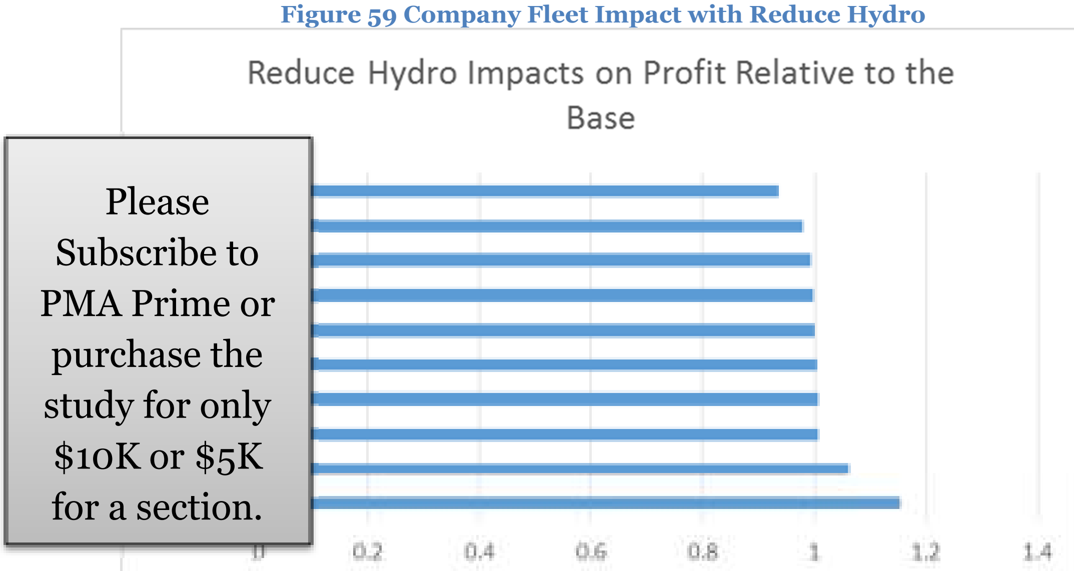
Figure 58 Company Fleet Impact with Positive Basis Spread



Reduce Hydro Sensitivity

Southern is the only company that has a material change in profit relative to the base case when hydro conditions are worse. NextEra and Calpine will benefit in this case.

Figure 59 Company Fleet Impact with Reduce Hydro



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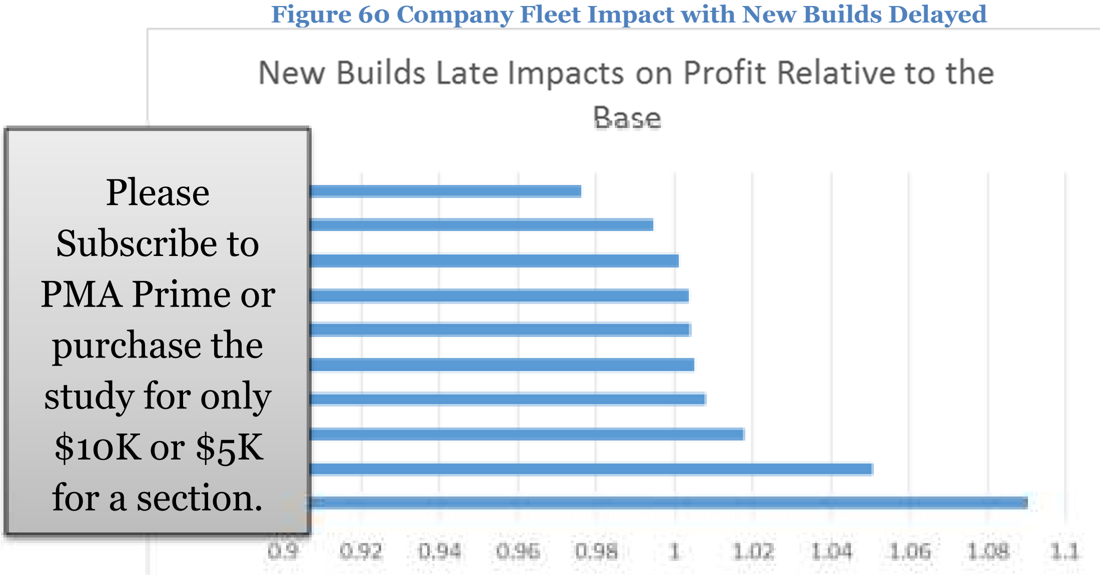
New Build Delays Sensitivity

The big winner is Calpine and NRG if new build plants are delayed a year from coming online or do not operate to their potential initially. Southern and TVA are impacted to the downside.

Figure 60 Company Fleet Impact with New Builds Delayed



Defer Retirement Sensitivity

No company's fleet performs better if retirements are delayed. Southern, Calpine, and NextEra are the worse of the bunch in this case.

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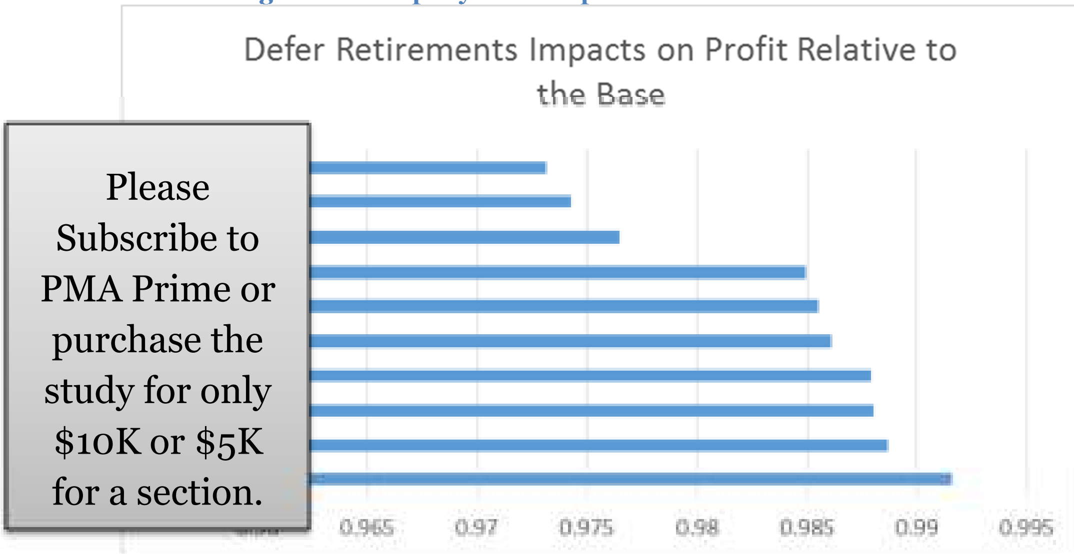
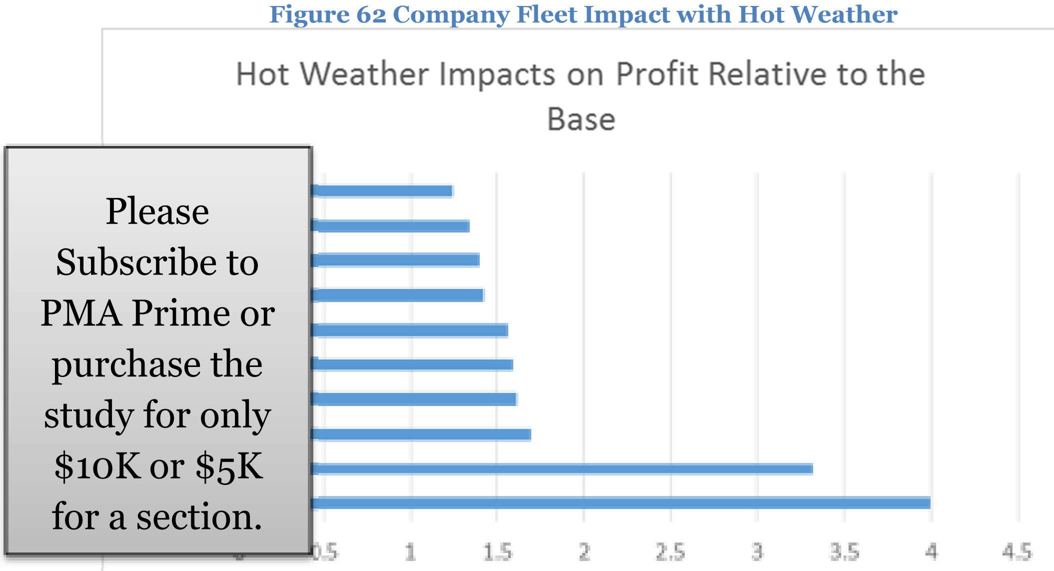
Figure 61 Company Fleet Impact with Deferred Retirements



Hot Weather Sensitivity

Big winners, in hot weather, are NRG and Calpine. Having units in supply tight areas with potential for price spikes is the reason NRG and Calpine do so well in this sensitivity.

Figure 62 Company Fleet Impact with Hot Weather



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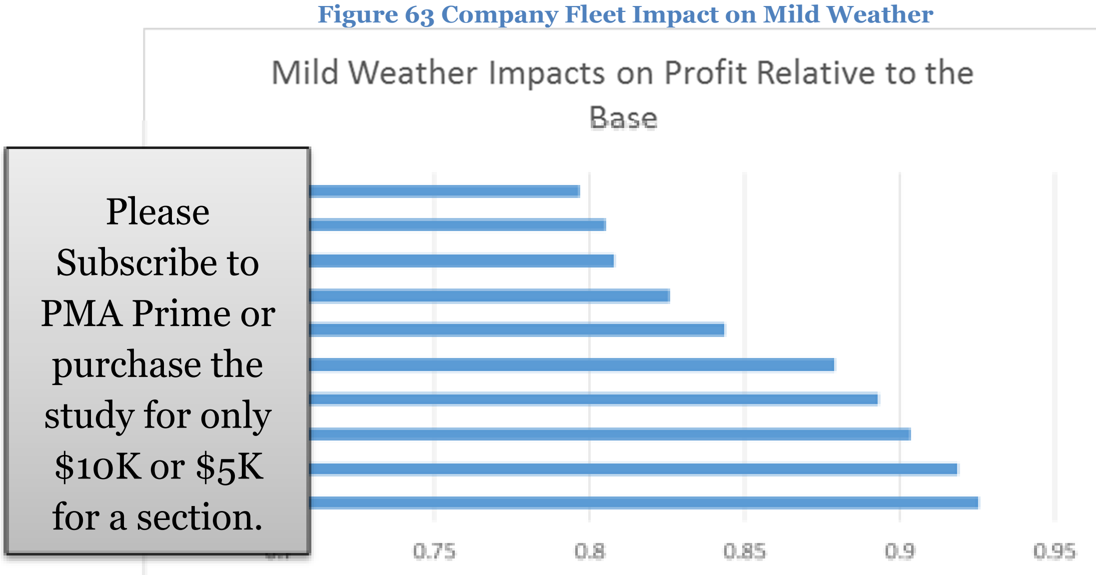
Mild Weather Sensitivity

If mild weather would occur, the biggest loser would be AEP. Profits could see a drop of 20% relative to the base case if this were to happen. Entergy at the other end of the spectrum would only see a drop of 7%.

Figure 63 Company Fleet Impact on Mild Weather



Duke Energy Corporation

Duke generation fleet does have above average risk to variability. Gas price impact is quite narrow compared to others. The downside risk of low gas prices are limited to a 10% loss relative to the base case.

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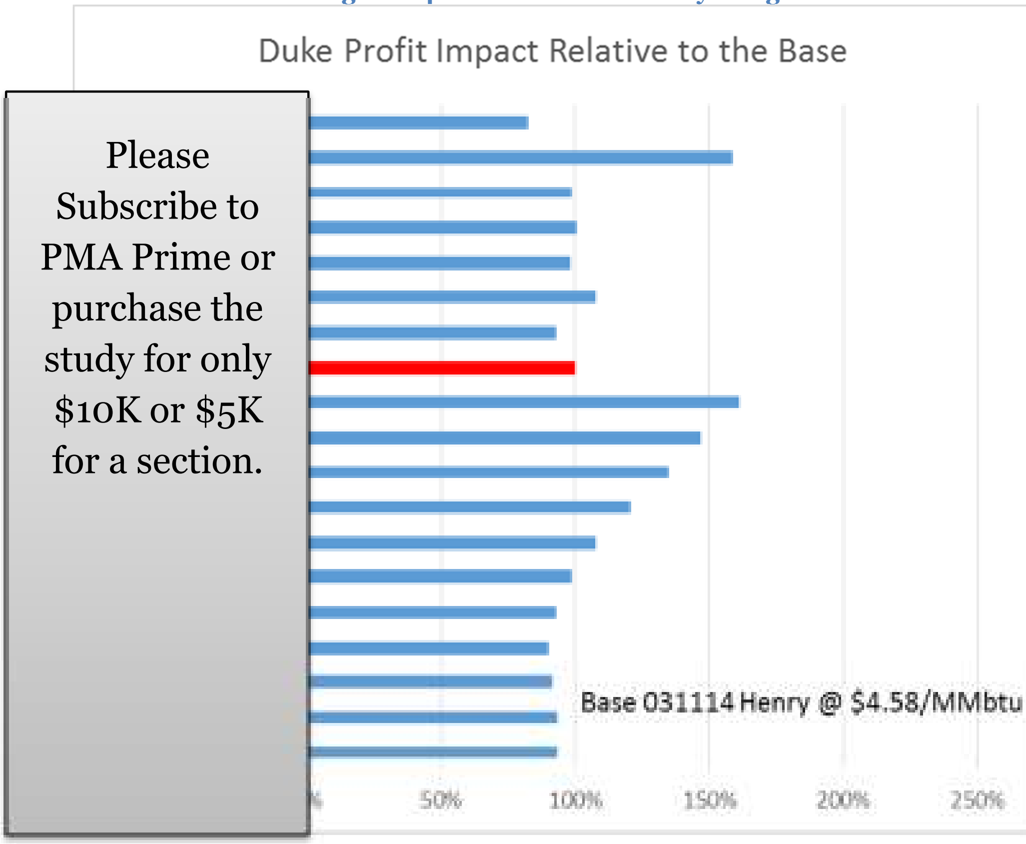
Figure 64 Duke Fleet Sensitivity Range



NRG Energy Inc.

NRG fleet is the second most to be subject to significant earnings fluctuations. There are some significant positive earnings fluctuations. Their portfolio is the number one most dependent on natural gas price in terms of profitability swing. The low gas prices can result in almost a 50% drop in profitability from the base case. Whereas an increase in price can increase fleet profitability by over 60%.

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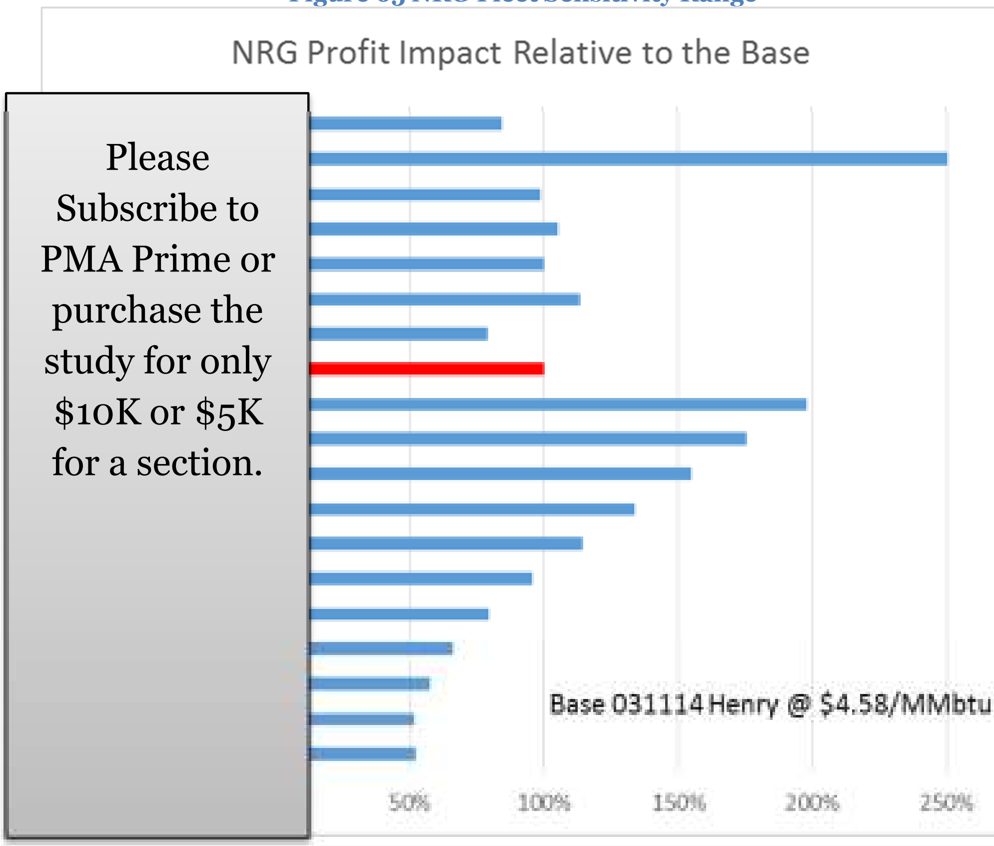
Figure 65 NRG Fleet Sensitivity Range



NextEra Energy Inc.

NextEra is similar to Duke showing slight above average for variance. They do have the least amount of variance when it comes to natural gas price. Low gas price downside is only 5%. A potential strategy could be to limit the hedging of gas for downside concern and focus on locking in profits to the upside movement of gas.

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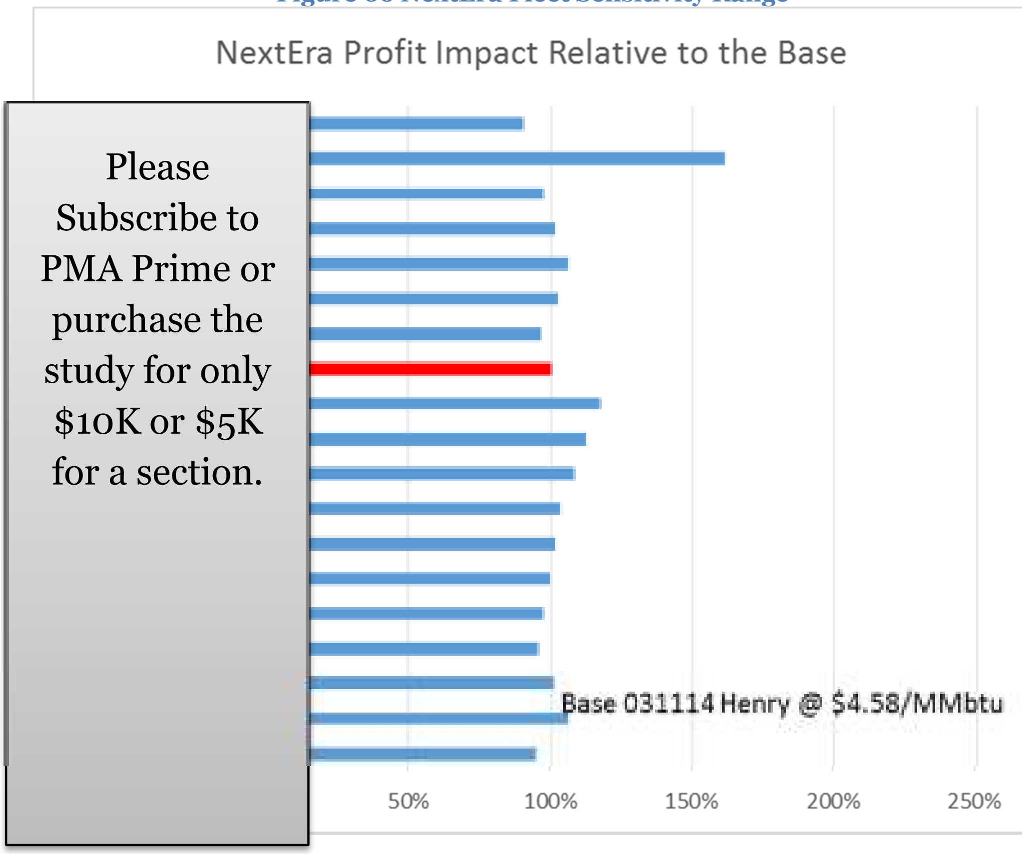
Figure 66 NextEra Fleet Sensitivity Range



Calpine Corporation

Calpine showed the largest variance. Fluctuations to earnings can be very large depending on the outcome of gas prices and load levels.

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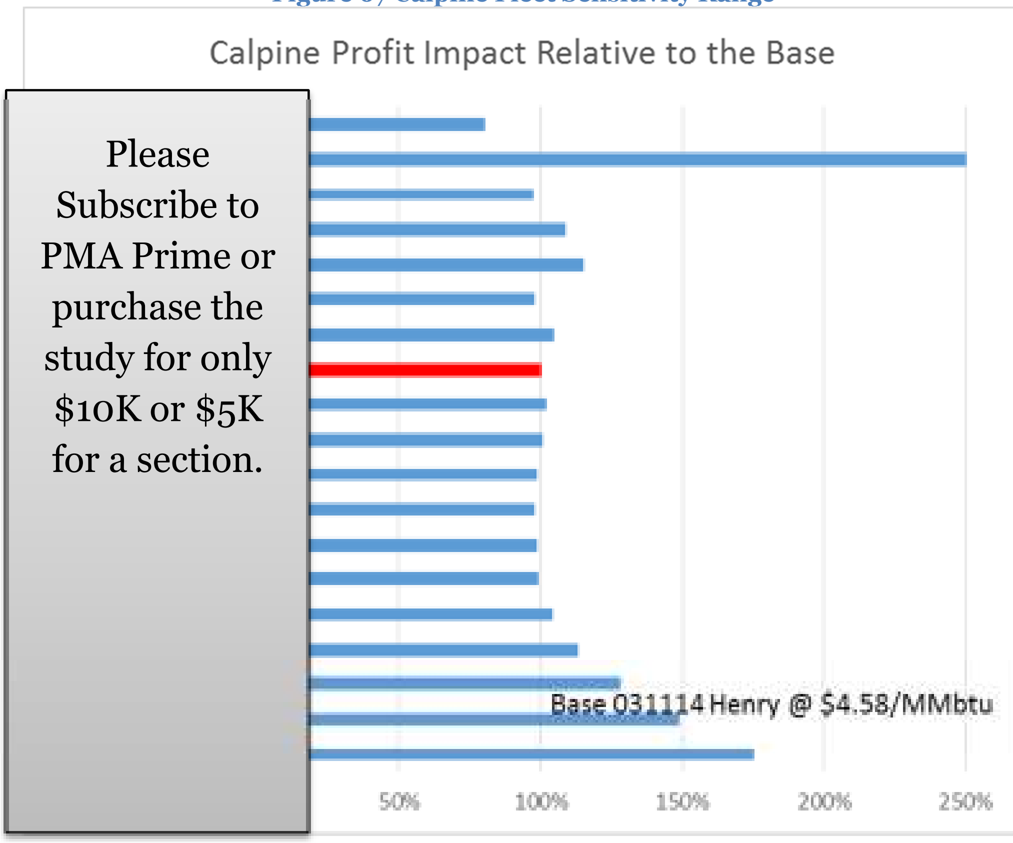
Figure 67 Calpine Fleet Sensitivity Range



Southern Company

Southern fleet is below average for variance. The fleet is less susceptible for earnings fluctuations. The fleet has the third largest upside to gas price rising relative to the base case.

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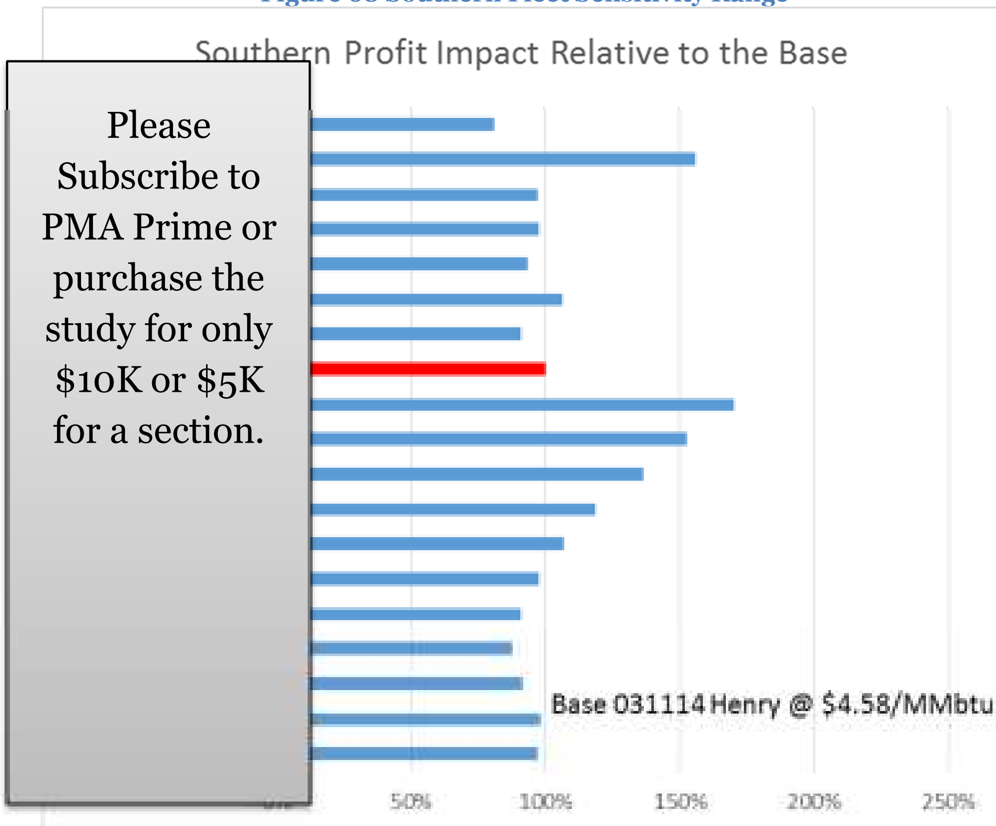
Figure 68 Southern Fleet Sensitivity Range



Tennessee Valley Authority

TVA fleet is the second least fleet for variance. However they are third place in the natural gas profitability spread. Gas prices below $4/MMbtu can cause fleet profitability to drop over 20%. When gas prices rise, this can cause an increase fleet profitability by over 20%. The swing can be almost 50%. This would suggest a smart natural gas hedging program could be wise decision.

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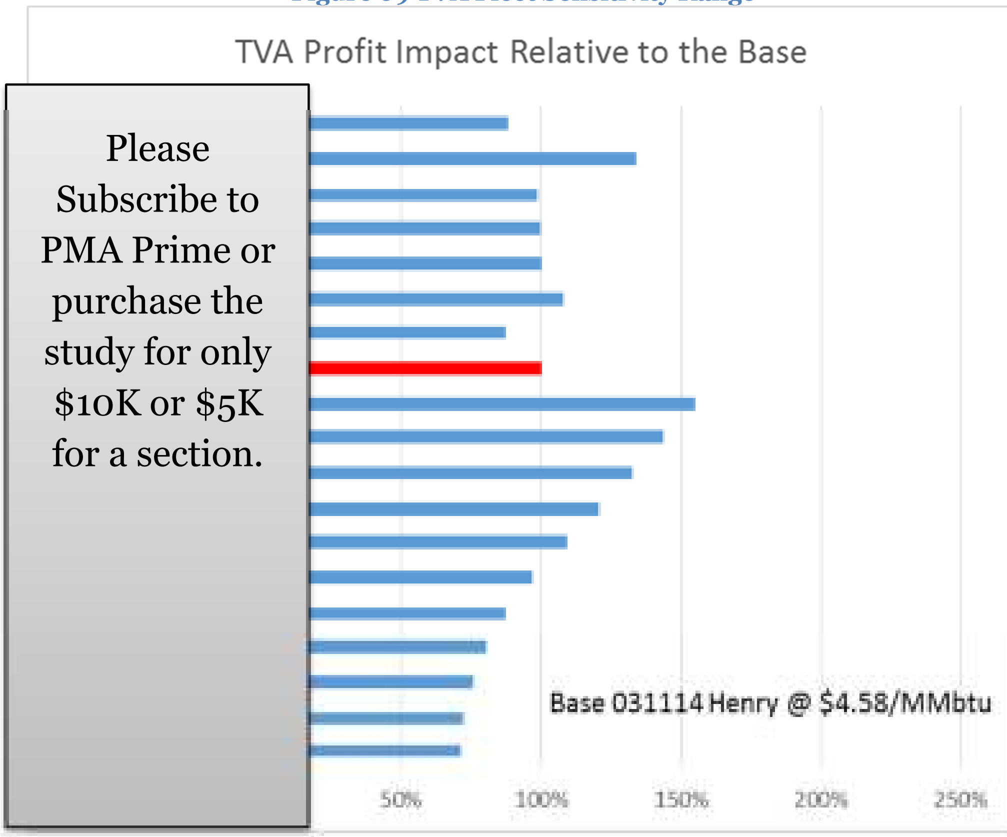
Figure 69 TVA Fleet Sensitivity Range



Exelon Corporation

Exelon is below the average in variance. They sit in the middle of the pack on the various sensitivities. They have a very symmetrical risk reward profile for gas. They are third from the bottom in terms of gains from high gas prices.

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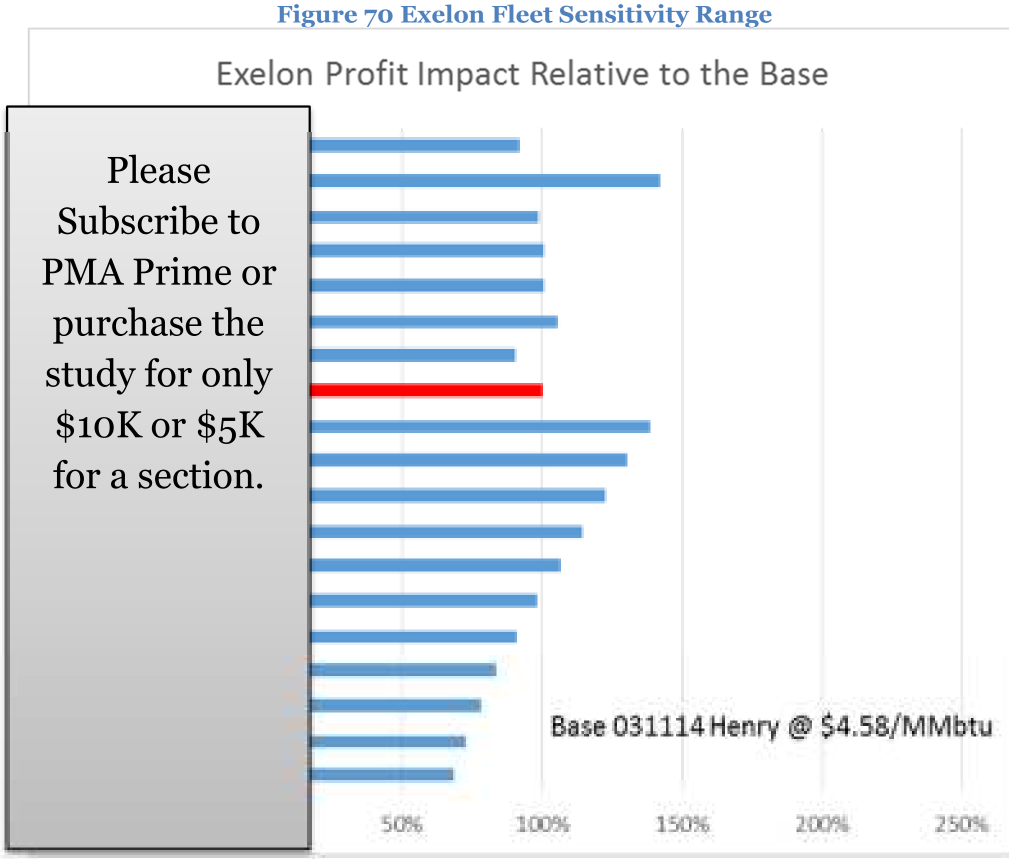
Figure 70 Exelon Fleet Sensitivity Range



Entergy Corporation

Entergy entire fleet produces the least volatility given the sensitivities used. They are susceptible to gas price swings and rank in the middle in terms of gas price impact to fleet profitability.

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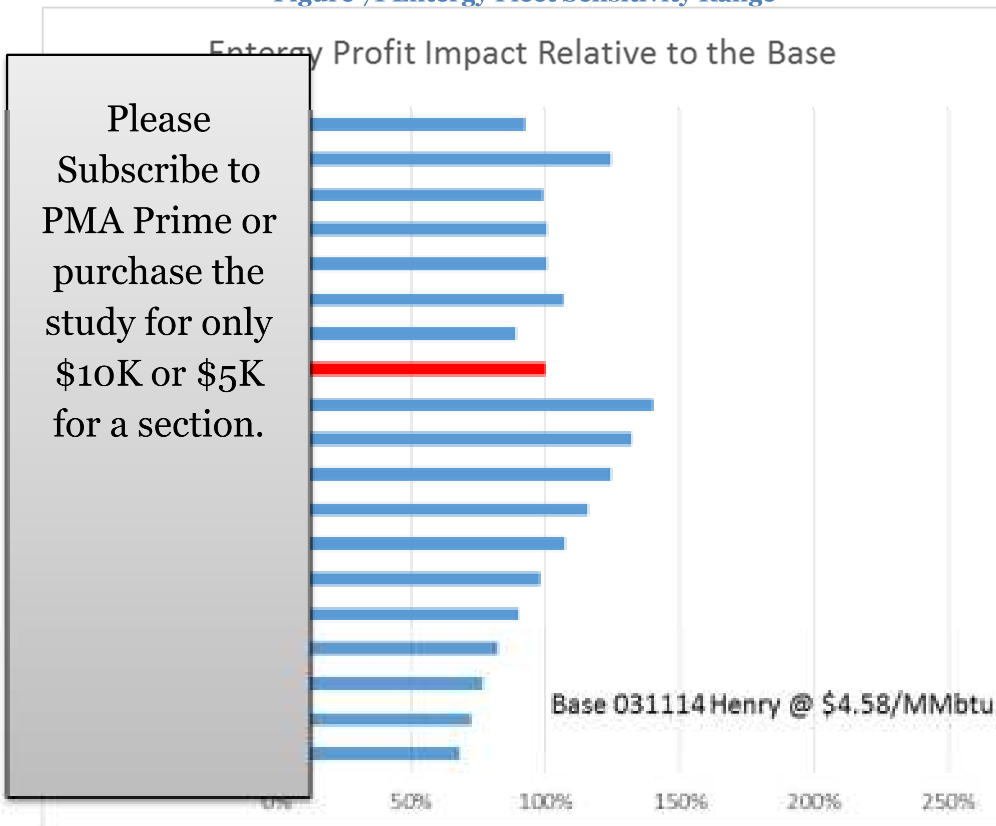
Figure 71 Entergy Fleet Sensitivity Range



American Electric Power Company Inc.

AEP is the second most dependent fleet on gas prices behind NRG. Gas prices can result in the fleet being 40% down or 60% up. Their fleet is also sensitive to the basis issues. They are the most susceptible to profitability drop if weather was going to be cooler than normal.

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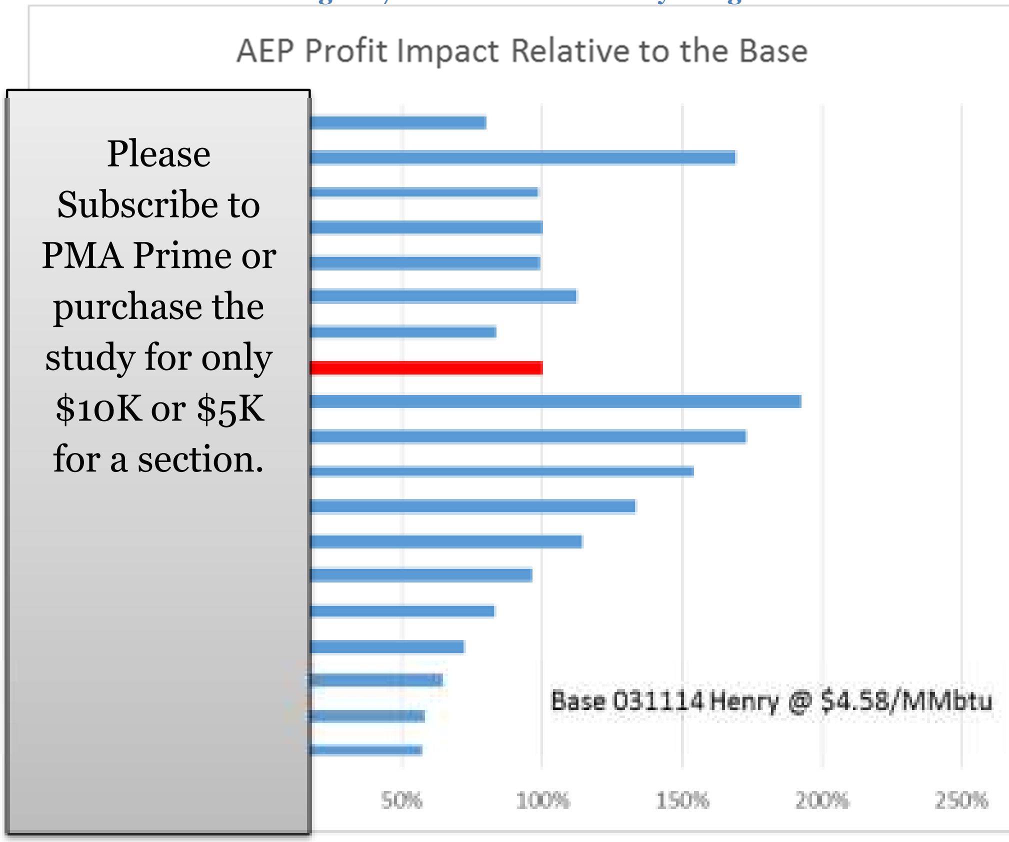
Figure 72 AEP Fleet Sensitivity Range



Dominion Resources, Inc.

Dominion is below the average on variance. The fleet is less sensitive to gas price relative to most companies.

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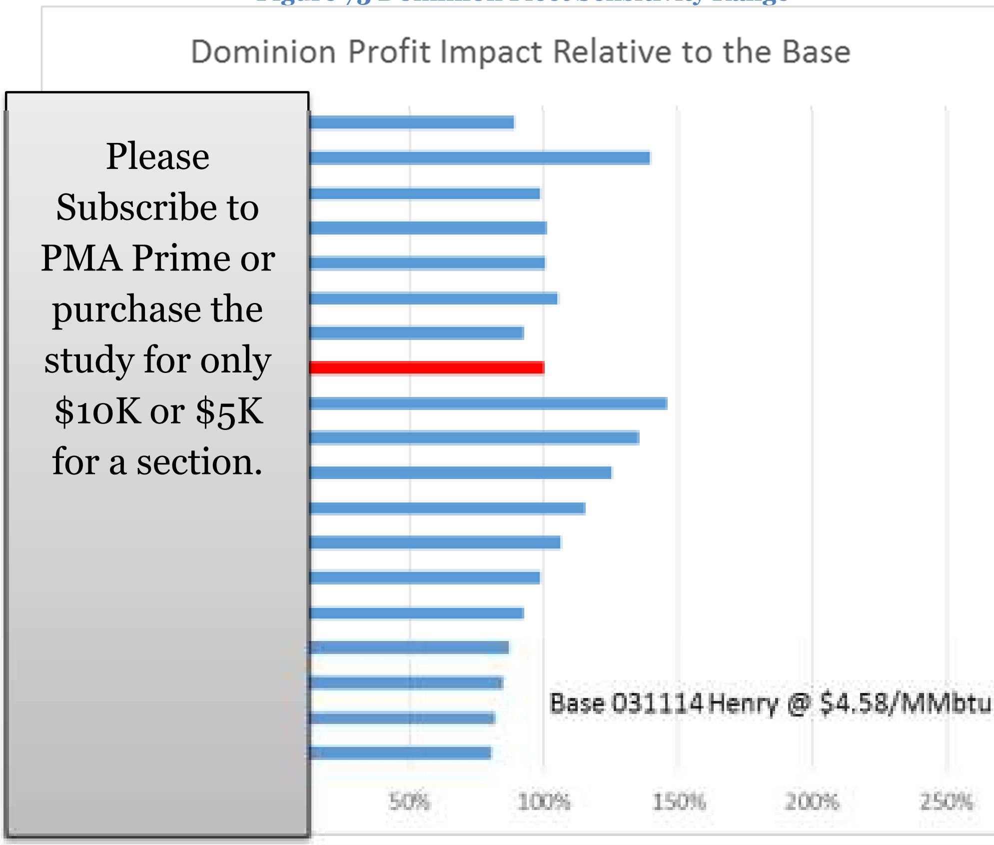
Figure 73 Dominion Fleet Sensitivity Range



Appendix

Validation

Fuel Validation

Gas is benchmarked to EIA Table 2.8 minus the Non-Contiguous Pacific using only the Electric Utility and Independent Power group.

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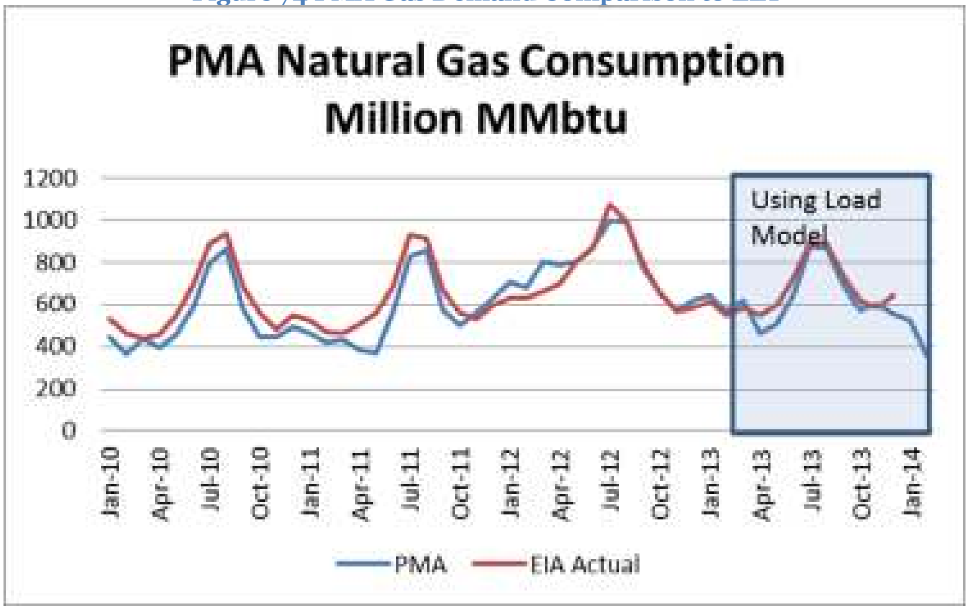
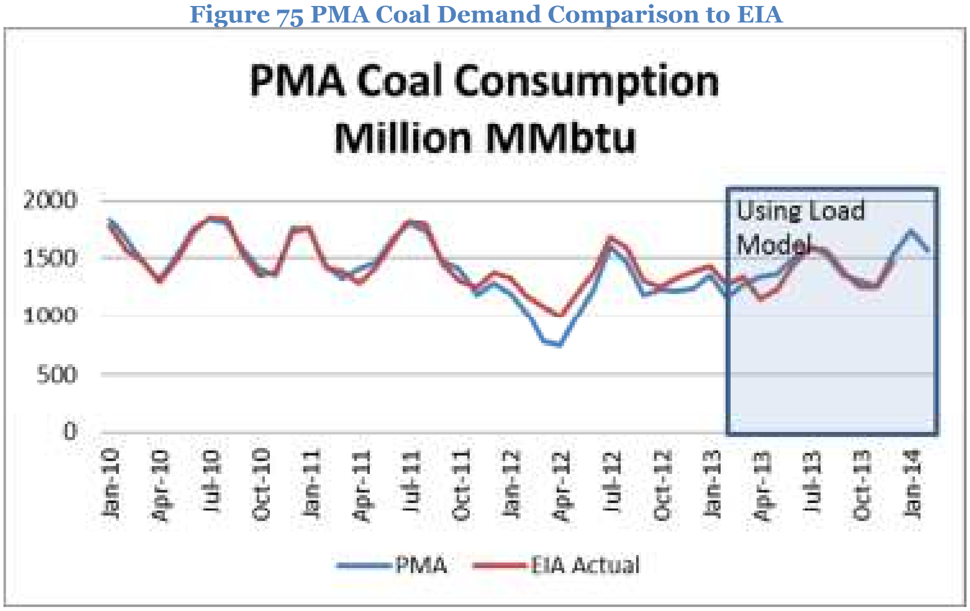
Figure 74 PMA Gas Demand Comparison to EIA



Coal demand is benchmarked to EIA – "Consumption for Electricty Generation (BTUs) for All Sectors" available in the Electricity Data Browser. A ratio was taken to extract the Non-Contiguous Pacific using Table 2.5.

Figure 75 PMA Coal Demand Comparison to EIA



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Power Price Validation

2013 forward is using computed loads from the load model created. Rest of history is using actual loads. More locations available upon request.

Figure 76 Nepool On-Peak Validation

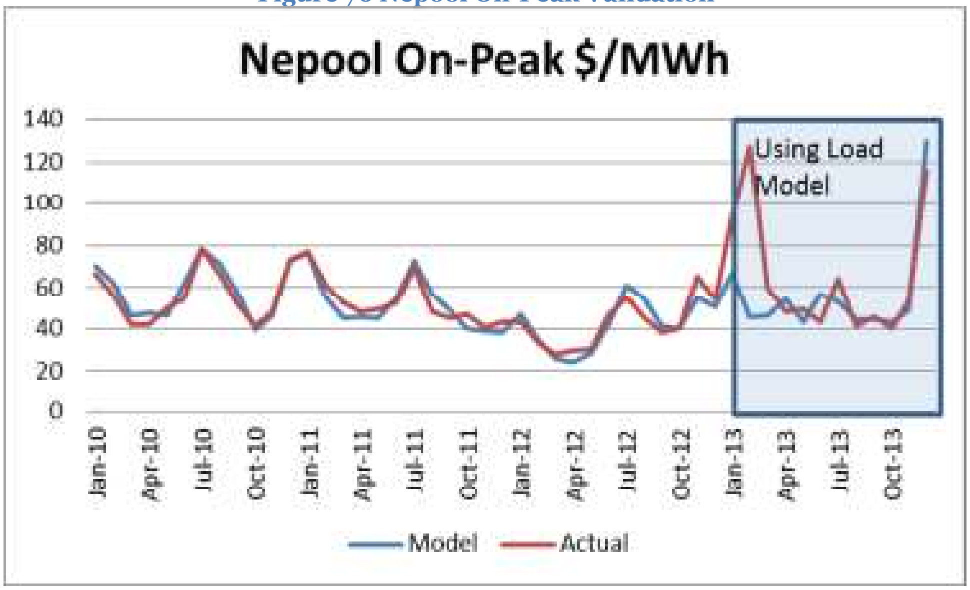

Figure 77 Nepool Off-Peak Validation

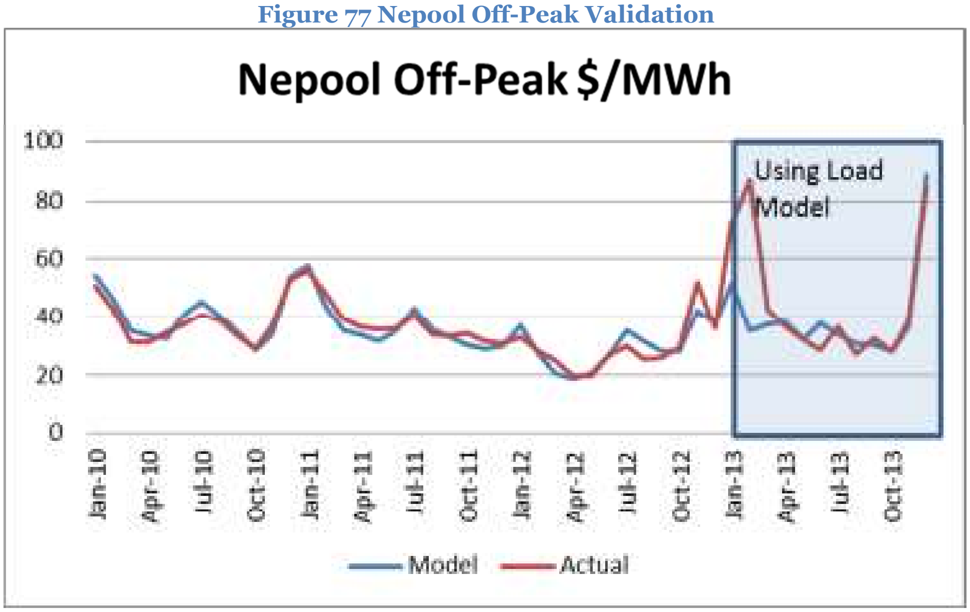

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Figure 78 NY Zone J On-Peak Validation

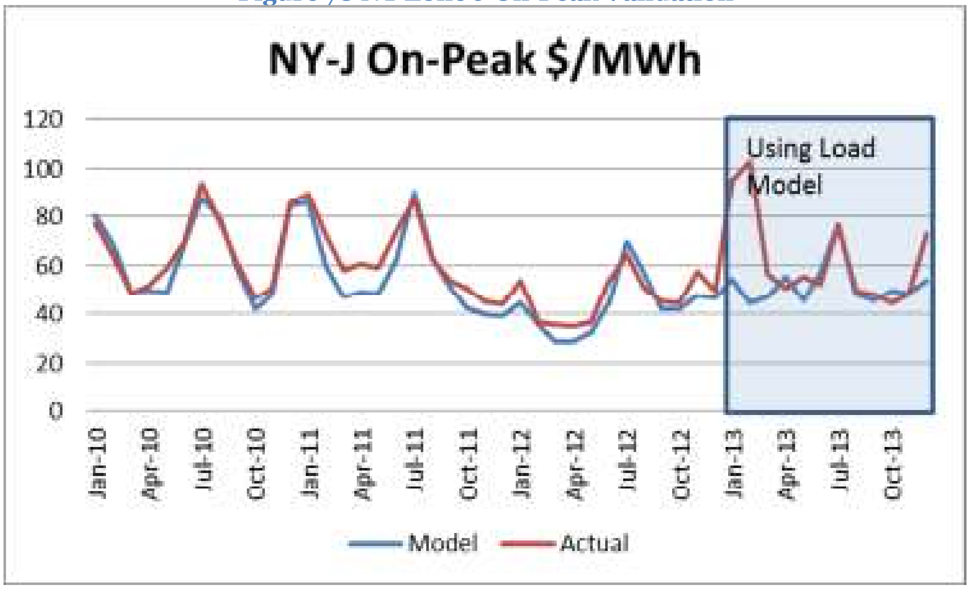

Figure 79 NY Zone J Off-Peak Validation

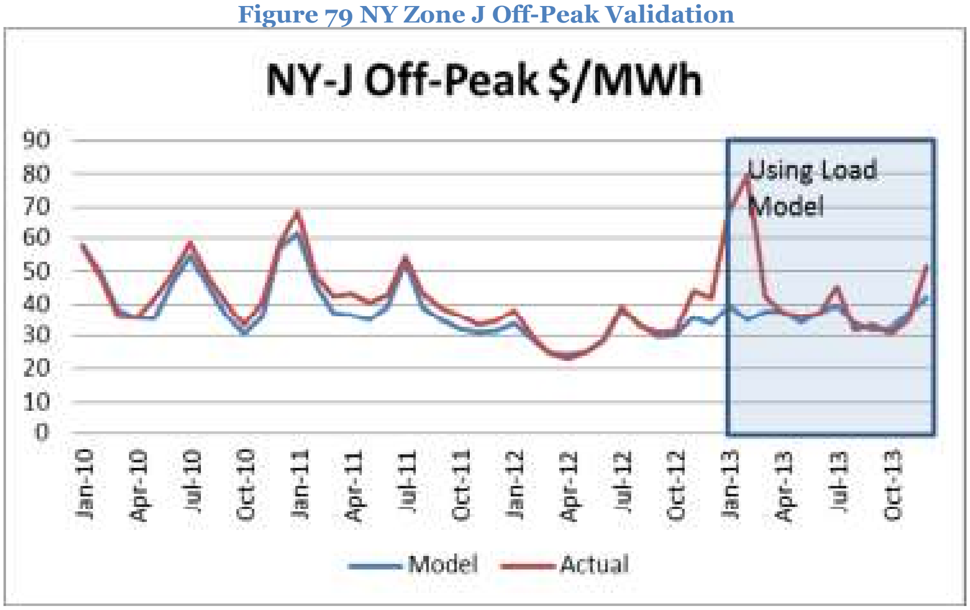

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Figure 80 PJM-West On-Peak Validation

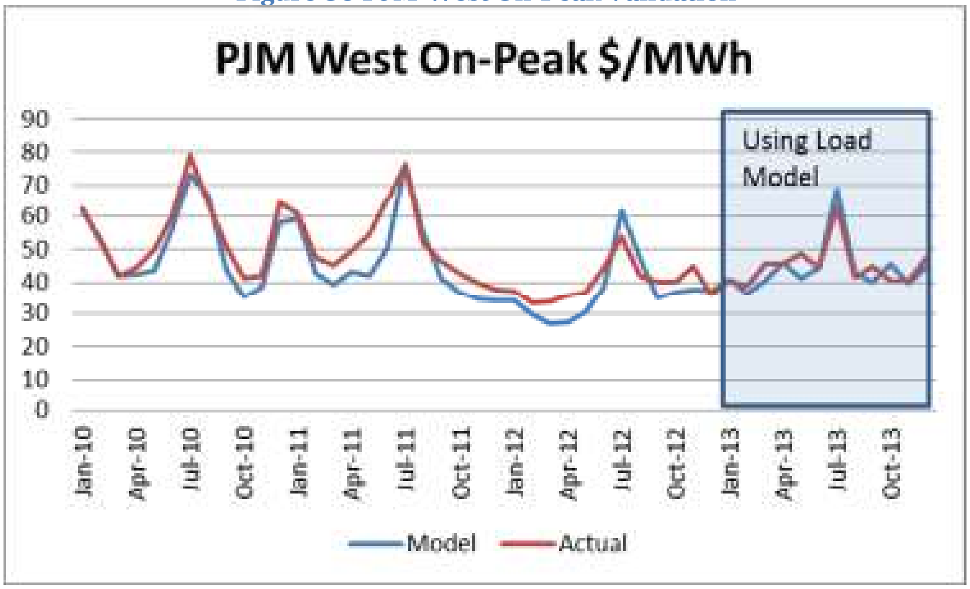

Figure 81 PJM-West Off-Peak Validation

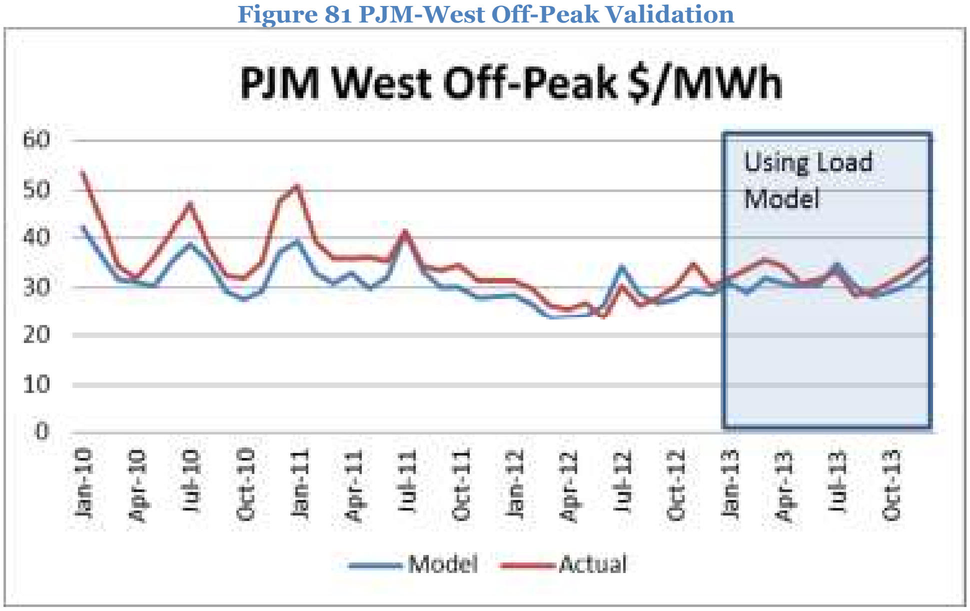

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Figure 82 AD-Hub On-Peak Validation

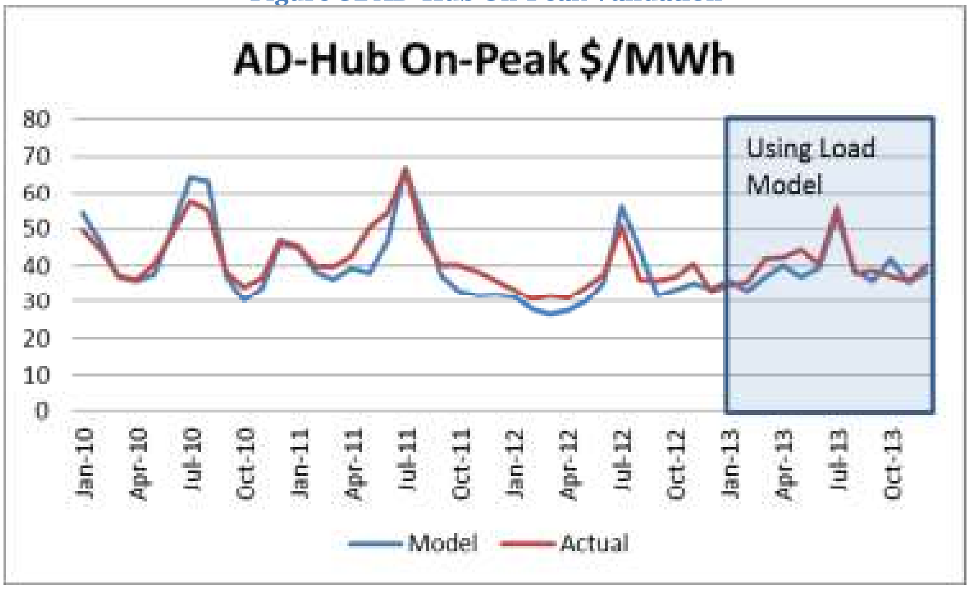

Figure 83 AD-Hub Off-Peak Validation

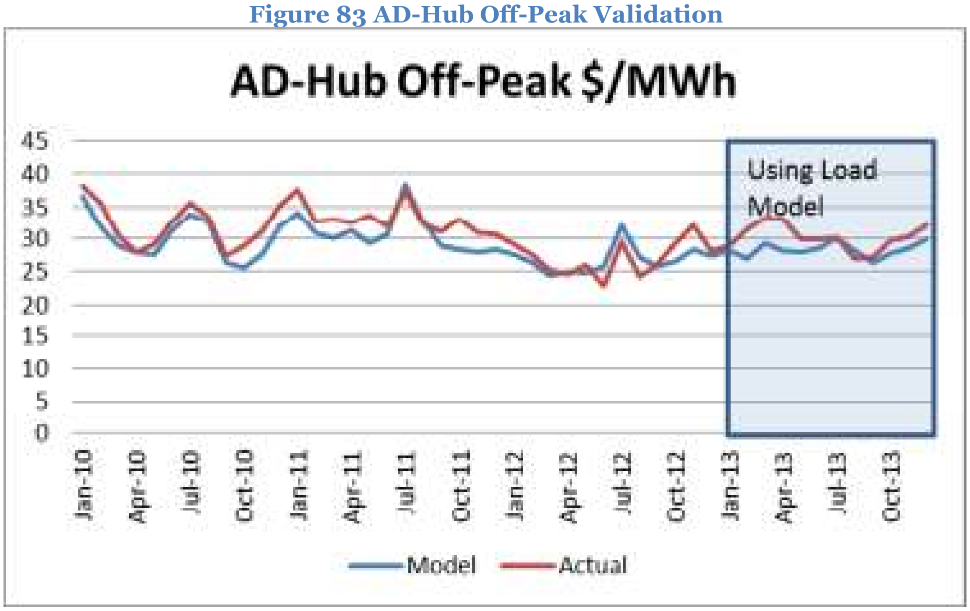

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Figure 84 ERCOT-Houston On-Peak Validation

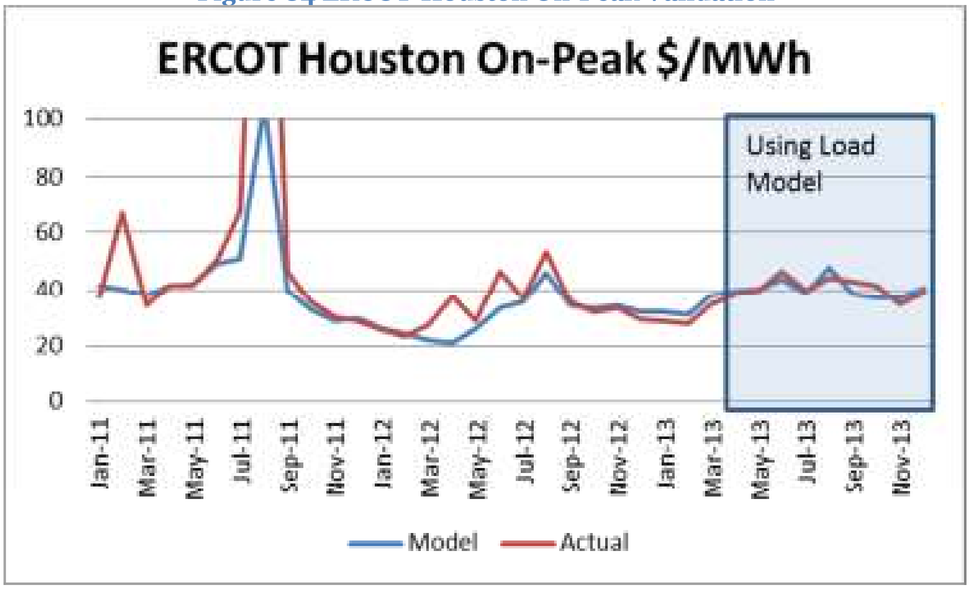

Figure 85 ERCOT-Houston Off-Peak Validation

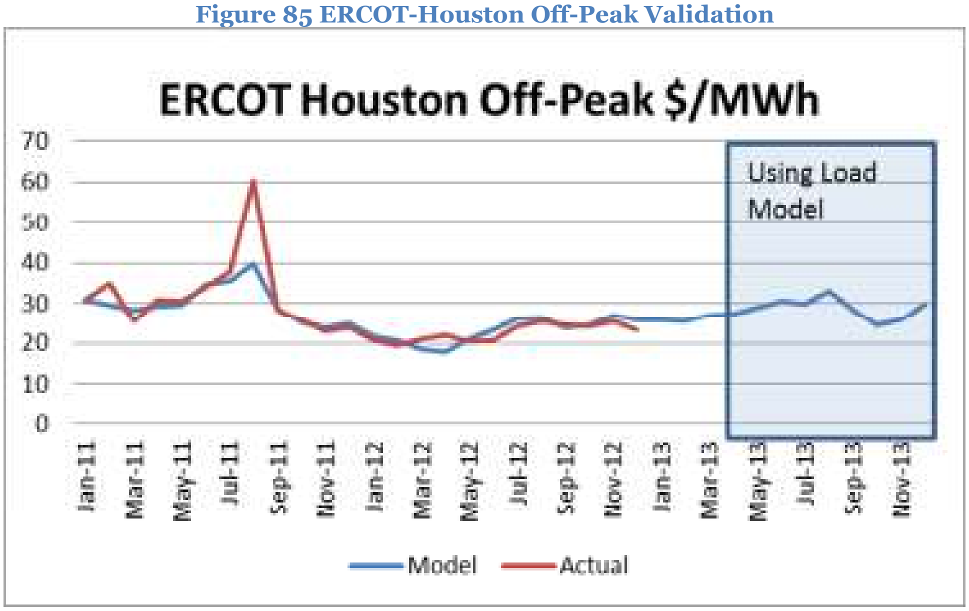

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Figure 86 Four Corners On-Peak Validation

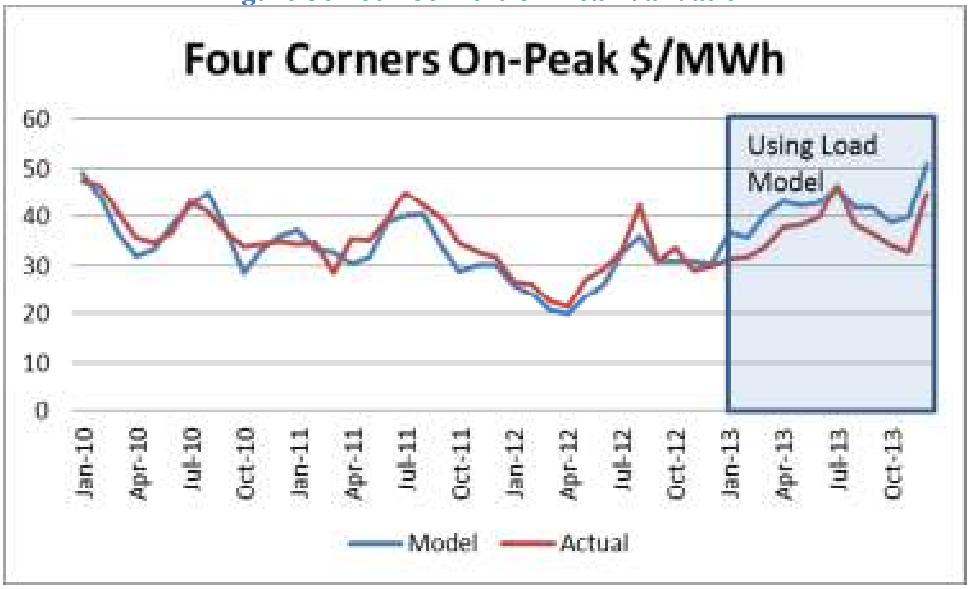

Figure 87 Four Corners Off-Peak Validation

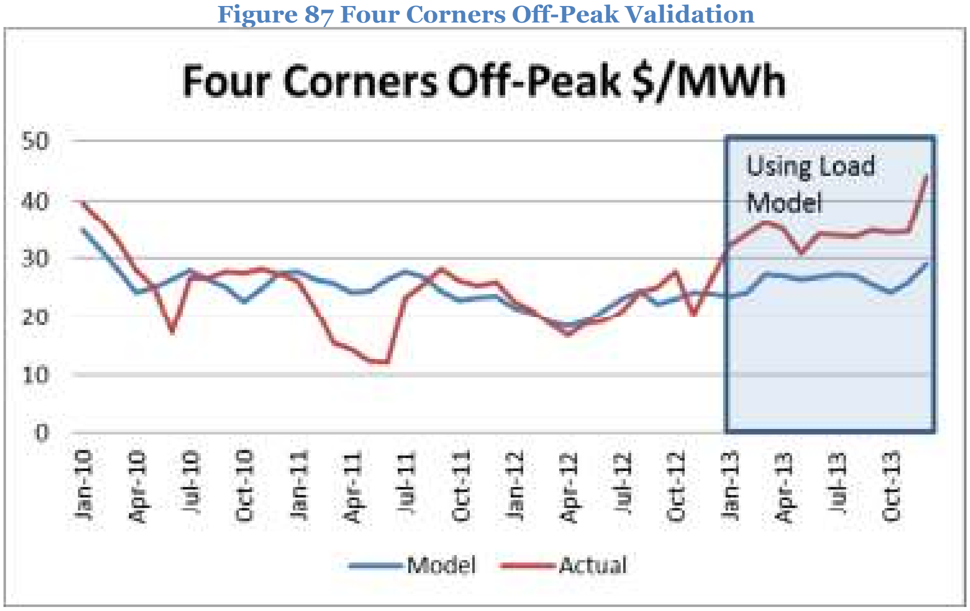

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Figure 88 Palo Verde On-Peak Validation

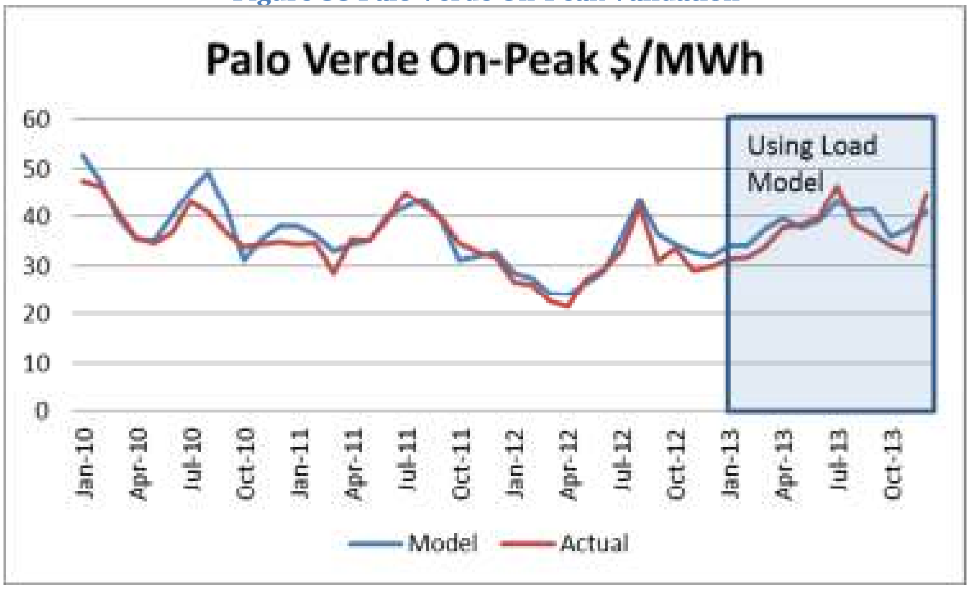

Figure 89 Palo Verde Off-Peak Validation

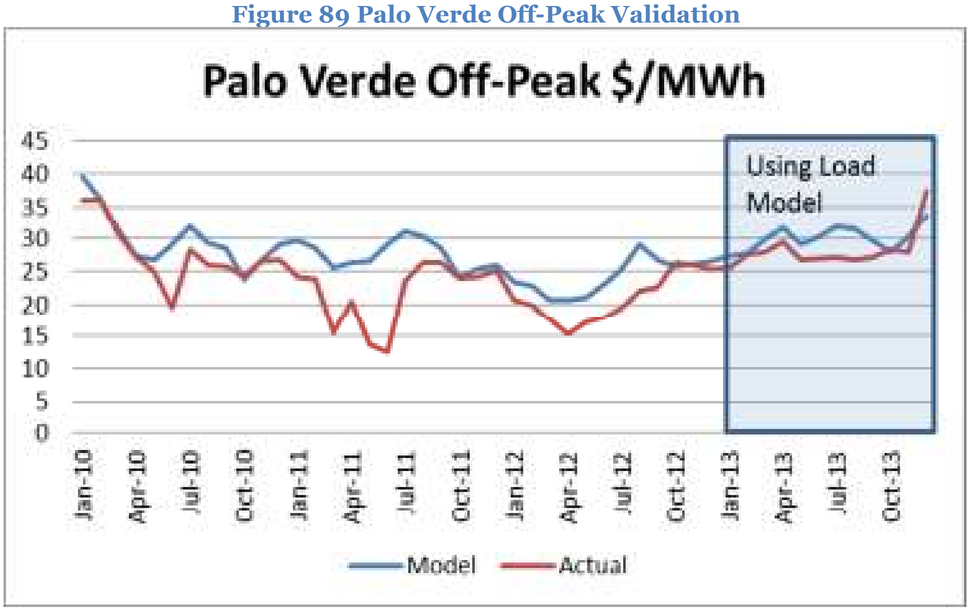

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Figure 90 Mid-Columbia On-Peak Validation

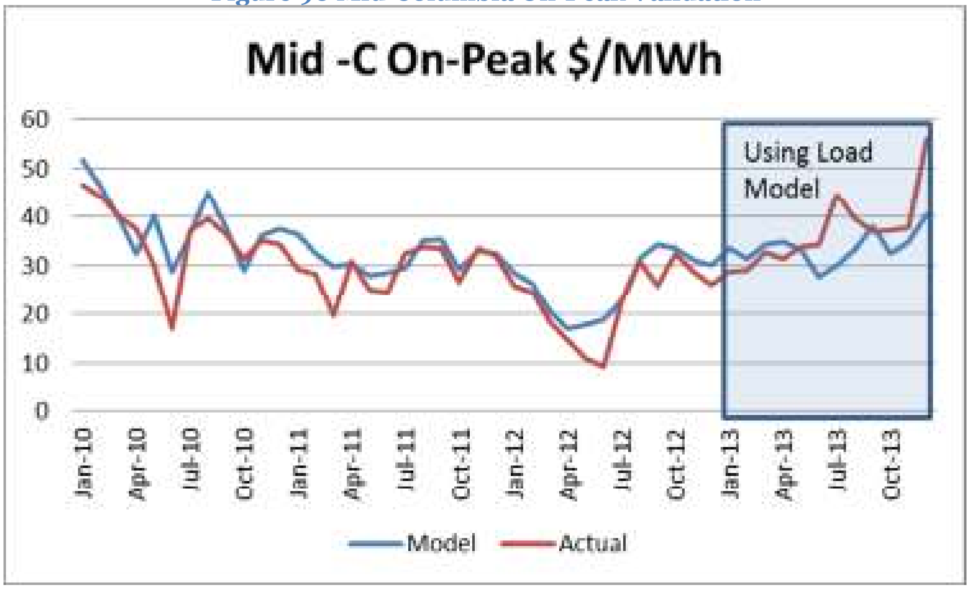
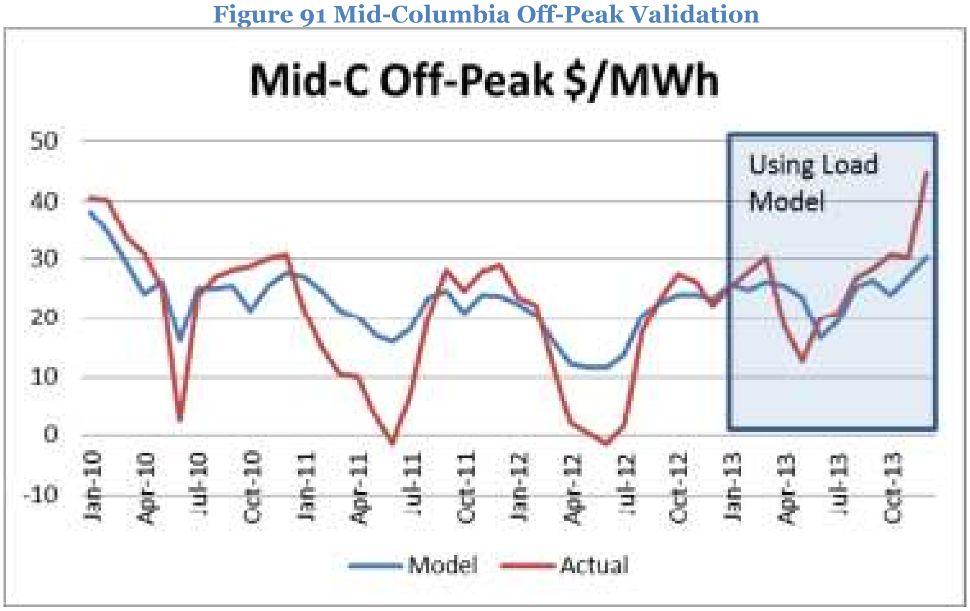


Figure 91 Mid-Columbia Off-Peak Validation



PMA Process

PMA involves many models and spreadsheets before it is assimilated by the dispatch model AuroraXMP.

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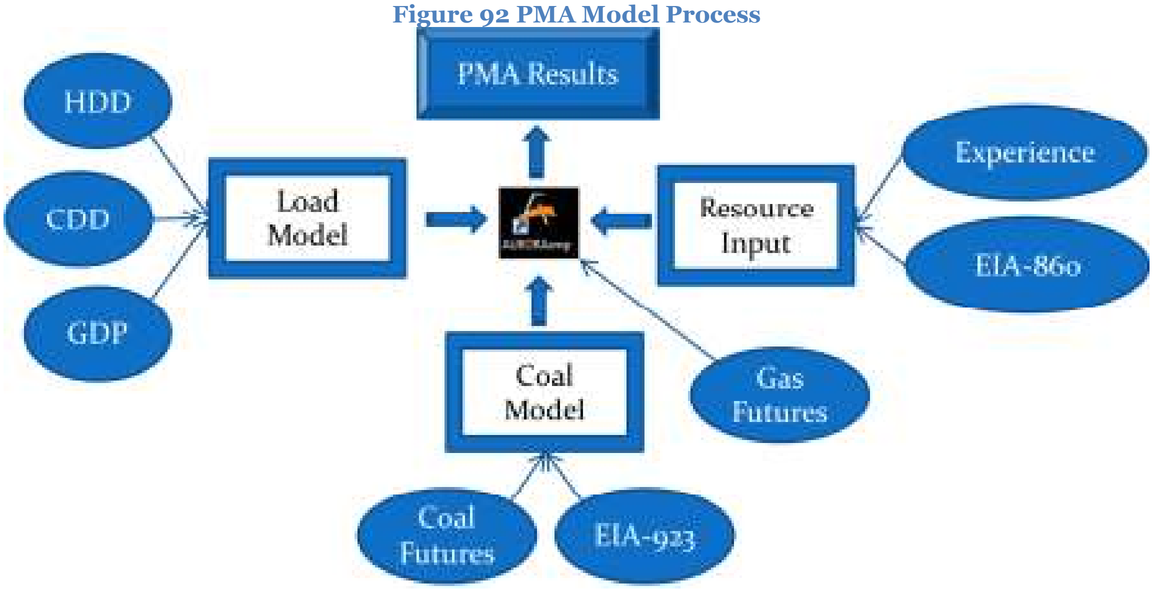
Figure 92 PMA Model Process



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