Assessing Economic Resilience of the North American Electricity Market Under Different Price Shocks to Natural Gas

by

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Abstract

After wide adoption of hydraulic fracking and renewable energy in the late 2000s, North America has seen a large influx of low-cost natural gas and increased renewable energy, both becoming main sources of electricity generation. The electricity market's reliance on natural gas increases its exposure to volatile natural gas prices. This paper investigates the economic resilience of the North American electricity market due to different renewable energy policies and natural gas price shocks. Under these price shock scenarios, the electricity market's resilience is measured the time required to recover the deviation from total system cost incurred by electricity market players relative to the business-as-usual scenario. Using the North American Electricity Model (NANELM), a partial equilibrium model that describes the behavior of electricity producers and transmission operators, we can measure the resilience and observe the behavior of generators and transmission operators. Although the electricity market reacts differently to different price shock scenarios, they show that the market is under-prepared for sudden changes in natural gas prices and current infrastructure prevents recovery back to the business-as-usual electricity prices.

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1 Motivation

1.1 The Changing Energy Landscape

With Earth's climate changing, new energy technologies rising, fuel supply shifting, and energy policies emerging and disappearing, the North American energy landscape will have to adapt to meet these complications.

With more utility-scale renewable energy generation connecting to the grid, modern power plants like solar and wind have the ability to produce electricity for little to no cost, making them economically competitive with existing fuel-burning power plants on the market. However, renewable generation is not guaranteed for all hours and relying on intermittent generation to form the majority of the generation mix exposes consumers and regions to higher volatility of prices [1][2].

In addition to new types of generation, innovations in acquiring and extracting energy commodities, like oil and gas, provide uncertainty in the supply of fuel for power generation in North America. In fact, the late 2000s saw a sudden change in energy prices when natural gas producers adopted hydraulic fracking. US natural gas production skyrocketed in the last decade as fracking became a more cost effective and efficient way to extract the fuel. Natural gas producers tapped into oil reservoirs stuck between shale slitstones and went on to increase the US share of shale gas from 5% in 2008 to almost 50% in 2014[3] [4]. Figure 1 shows the historical and projected growth of shale gas and tight oil production starting in 2008, which is projected to grow without diminishing up to 2040. During the late 2000s, this increase in natural gas supply lowered the price of natural gas dramatically and ignited investments in new natural gas power plant capacities. In 2018, this led to the first instance of natural gas power plant capacity surpassing coal power plant capacity in the US [5]. As seen in Figure 2, the last few decades have seen a steady increase in new combined cycle capacity and a decrease in coal electricity generating capacity.

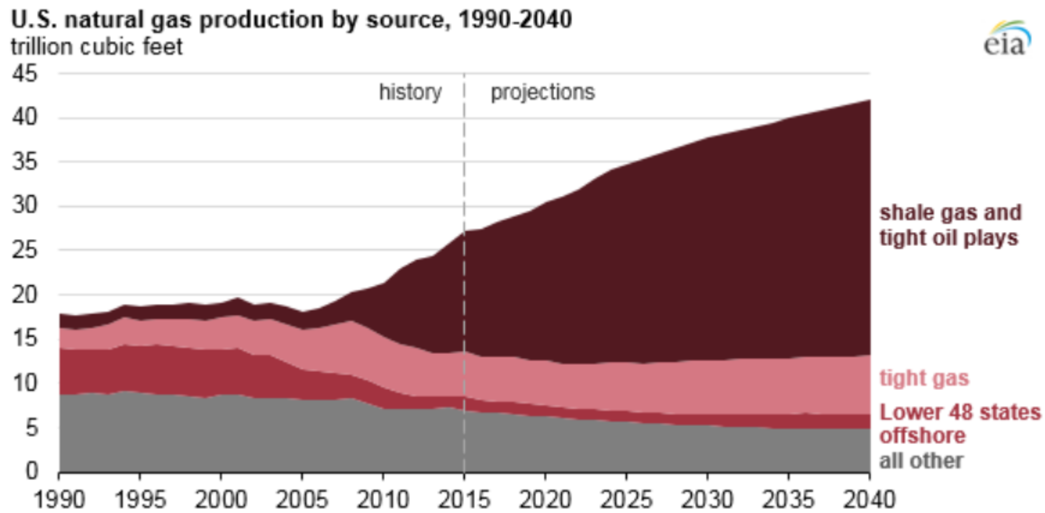


Figure 1: Historic and Projected Growth of Natural Gas Production in the US [4]

Beyond balancing changing electricity production and growing energy consumption, federal and state governments have turned to policies to reduce the harmful effects of greenhouse gasses, leading to retiring fossil fuel plants. With all these changing factors in the energy landscape, how can we best invest in electricity infrastructure to maintain electricity market stability?

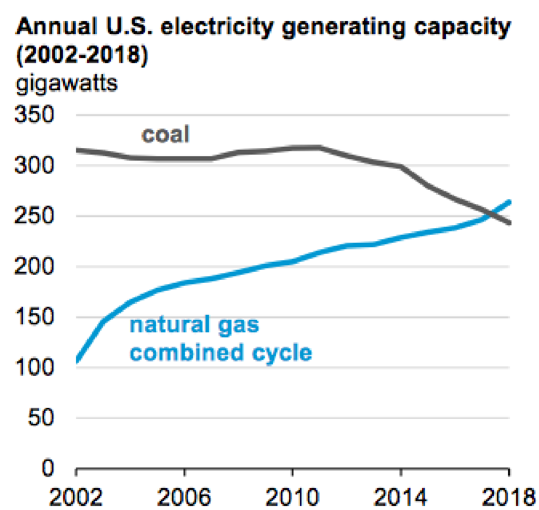


Figure 2: Coal vs Natural Gas Combined Cycle Electricity Generating Capacity [5]

1.2 Objective

The North American energy industry has invested heavily in natural gas infrastructure since the rise of fracking. However, there still lies inherent uncertainty in the future supply of natural gas; namely, there is no guarantee the price of natural gas will stay low for the next few decades.

This paper investigates the economic resilience of the North American electricity markets under natural gas price shock scenarios. Under each scenario, a price shock perturbs the system in 2030 from the business-as-usual scenario and two factors are observed to measure the system's resiliency performance: the change in system cost and the time it takes the deviated system cost to return to the baseline scenario. The goal is to assess the magnitude of change and how long it takes for the North American electricity grid and market to recover.

1.3 Electricity Infrastructure and Its Effect on Electricity Prices

Electricity infrastructure includes generation (power plants) and transmission lines. Each region differs in its production and connectivity to other regions. For example, Quebec's hydroelectric dams produce most of the region's electricity, more than enough to transmit across the border to the US, whereas North and South Carolina rely heavily on coal and natural gas to produce electricity [6]. These differences in fuel mix set the regional electricity price, also known as locational marginal price (LMP)[7].

In North America, the locational marginal price is determined by the last unit of electricity cleared on the market, either produced by a local power plant or imported through transmission. On the generation side, power plants are selected to produce electricity based on their selling price and they are selected until all demand is met. An example of this can be seen in Figure 3, where plant types A-C are chosen to generate at their capacity and only part of plant type D is chosen to meet this demand. The LMP of this particular demand is then set by the marginal cost of plant D for this region.

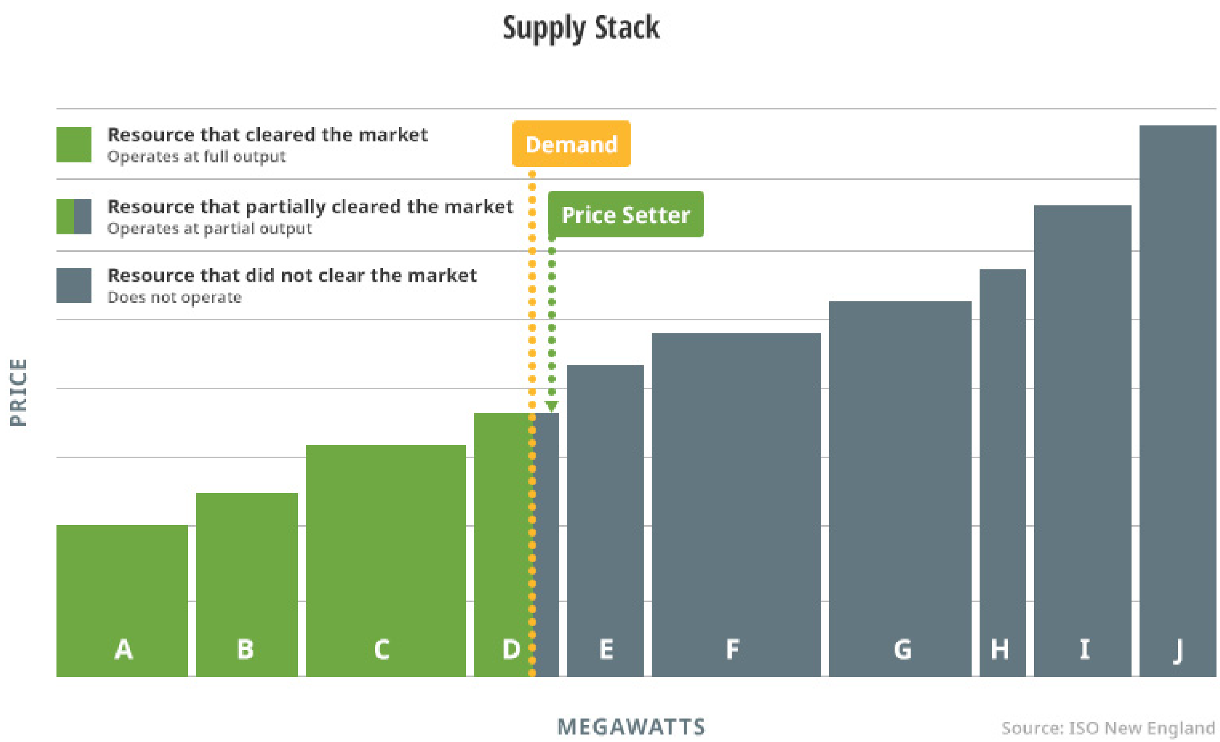


Figure 3: Market Clearing Example in from the New England Independent System Operator [9]

1.4 Electricity Infrastructure and Its Effect on Regional Resilience

This close connection between the regional price of electricity and the producer's marginal cost shows the important relationship between electricity infrastructure and the region's electricity price volatility, especially when changes occur to the system. With long-term uncertainties in energy resources, a region's price could change drastically. Regions with a more diverse set of energy infrastructure usually fare better when changes occur in their system [13]. An increase in the price of coal could lower coal plant electricity production in the region, but with a varied electricity infrastructure, the region has the choice of shifting their production elsewhere, or even importing from other regions [1].

Though regions in North America are starting to see more variety in their production, most regions still rely heavily on a few dominant fuel types. In Canada, over 50% of their electricity is produced by hydroelectric plants; while in Southeastern United States, coal and natural gas plants powers homes and offices. This narrow set of fuel types leaves regions susceptible to high volatility in electricity price if their respective plant costs increase.

This study focuses on investigating how the electricity market reacts to natural gas price volatility. Similar to the fracking boom in 2008, a particular scenario depicts a sharp decrease in natural gas price. However, the opposite could occur in the future. In another scenario, gas supply is lower than predicted and natural gas prices see an sharp increase. With these two possible outcomes, the need to measure any region's ability to adapt to a new normal is paramount.

1.5 Measuring Resilience

Resiliency has been defined differently thoughout the energy industry. Some metrics, like total days of power outage or generation loss, are used to assess the short-term resiliency [13][15][16]. However, these metrics do not inform us of long-term effects in the system. Instead, understanding the system's adaptability is more appropriate. As price shocks shift the system equilibrium, the goal is to understand how regions in North America can adapt without drastically increasing the regional system costs. Furthermore, understanding the time it takes for a region to return to its previous state is also an important metric for assessing the system's resiliency.

For this paper, the metric of resilience is the change in the overall system cost relative to the base case by a particular price shock scenario ($scen$).

$$R_{scen} = \iint\limits_{t,reg} c(t,reg)\Big[LMP_{scen}(t,reg) - LMP_{base}(t,reg)\Big]\mathrm{d}t\mathrm{d}reg \tag{1}$$

where R_{scen} is the resiliency metric represented by the change in the regional system cost in \$ due to a particular price shock scenario, $c(t)$ is the consumption at year t, $LMP(t,reg)$ is the locational marginal price at year t and in region reg. This metric measures the economic deviation from the base case due to different supply shocks and/or policy enforcement scenarios. It is important to note that this metric is unbounded, meaning that the sign of the metric also plays an important role. A positive deviation indicates an increase in system cost; conversely, a negative deviation indicates a decrease in system cost.

Other than the change in system cost, understanding how long it takes for a region to adjust its course back to the baseline shows the system's ability to adapt quickly. This can be measured by looking at the time taken to return to the projected baseline cost. As the system cost recovers from the price shock, the probability of the system returning exactly back to the baseline cost is low; therefore, any recovering system cost that is within 1% of the original baseline system cost is considered to have returned to normal. The time taken to recovery is given by the follow equation:

$$T_{scen}(reg) = t_{recover}(reg) - t_{shock}(reg) \quad \forall reg, scen \tag{2}$$

where T_{scen} is the time in years it takes for a region to return back to the baseline system costs within 1% after inducing a supply shock scenario, $t_{recover}$ is the year that the scenario locational marginal price returns to the base case system cost, and t_{shock} is the year that these shocks are induced to the whole system which is 2030 for our model. Although this metric is specific to this model, a two-factored approach to assessing resilience has been used in other long term planning models [14][25].

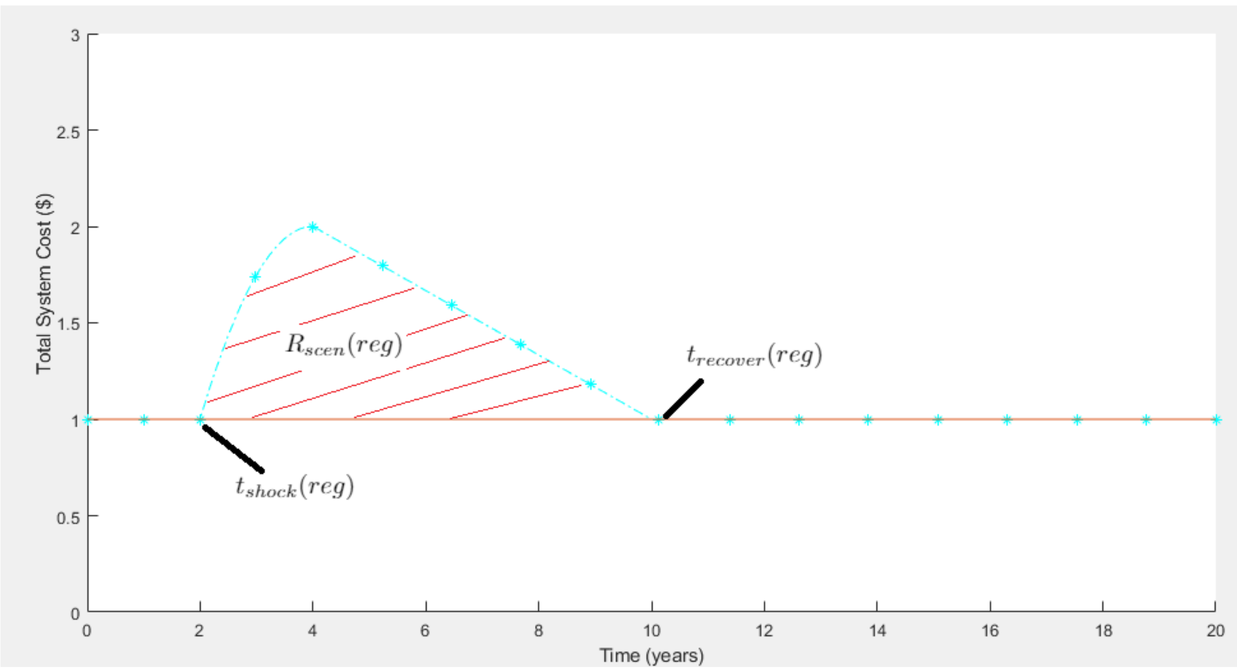


Figure 4: Example of Measuring Resilience with NANELM

2 Model Data and Data Manipulation

2.1 Traditional Energy Modeling

For the last two decades, long-term energy planning models have been the backbone for providing insight and guiding decisions in investments for grid scale energy infrastructure expansion. Traditional energy models look solely at the electricity market to provide insight on how to make decisions, without considering commodities endogenously. For the most part, a basic economic energy model's constraints and parameters can be modeled as a mixed integer linear program [19]. However, with the rising complexity of energy markets, understanding the interconnections between market players is imperative to provide insight on how best to make investments for the future [20].

Encapsulating different energy markets proves to be quite difficult in traditional energy modeling with optimization techniques like mixed integer linear programming. Firstly, modeling physical properties like generation, consumption, transmission, and policies of all the different market players contains nonlinear relationships. Secondly, the complexities involved in modeling market interactions make traditional optimization techniques undesirable [21].

To combat these difficulties in a mixed market structure, this model employs the use of mixed complementarity modeling.

2.2 Mixed Complementarity Problems

Mixed complementarity problems (MCP) have been imperative in many important modeling classes like Nash-Cournot games and location marginal pricing equilibria [7][21][19]. In terms of energy modeling, complementarity models generalize the Linear Programs, Quadratic Programs, and Convex Nonlinear Programs with the use of Karush-Kuhn Tucker Conditions (KKT Conditions). A particular emphasis on convexity in the constraint space and objective function must be made to ensure that the problem formulated will guarantee an optimal solution with the use of KKT Conditions [21][22][23].

To illustrate a complementarity problem, we take a generic optimization problem and express it as a complementarity problem. Given a generic optimization problem with m inequality constraints, n equality constraints, and an objective function $f(x)$:

$$\text{Minimize}_x \quad f(x)$$

$$\text{s.t.}$$

$$g_i(x) \leq 0 \quad \forall i = 1, ..., m \quad (\alpha_i)$$

$$h_j(x) = 0 \quad \forall j = 1, ..., n \quad (\beta_i)$$

With the help of KKT conditions capturing the primal problem and Lagrange multipliers acting as the dual variables, this problem is equivalent to this complementarity problem:

$$\nabla f(x) + \sum_{i=1}^{m} \alpha_i \nabla g_i(x) + \sum_{j=1}^{n} \beta_j \nabla h_j(x) = 0 \quad \forall i, j$$

$$\alpha_i \geq 0 \quad \forall i$$

$$g_i(x) \geq 0 \quad \forall i$$

$$\alpha_i g_i(x) = 0 \quad \forall i$$

$$h_j(x) = 0 \quad \forall j$$

$$\beta_j \text{is free} \quad \forall j$$

For simplicity, one can combine the KKT condition for inequalities by simply using the $\perp$ operator:

$$\nabla f(x) + \sum_{i=1}^{m} \alpha_i \nabla g_i(x) + \sum_{j=1}^{n} \beta_j \nabla h_j(x) = 0 \quad \forall i, j$$

$$0 \leq g_i(x) \perp \alpha_i \geq 0 \quad \forall i$$

$$h_j(x) = 0 \quad \forall j$$

$$\beta_j \text{is free} \quad \forall j$$

Note that problem is not formulated with a clear objective function nor with the general structure of an optimization problem. Instead the primal and dual problem are incorporated into a system of KKT conditions. A mixed complementarity model's power lies in the ability to combine optimization problems. In the case of energy models, each producer and transporter's objective and constraints can be expressed in this tidy formulation.

3 The Model

The North American Electricity Model (NANELM) is a long term capacity expansion model with a partial equilibrium approach, capturing two different market players: producers and transmission operators. The ultimate goal for this model is be coupled with its sister models, like the North American Natural Gas Model (NANGAM) [24]. With this structure, the models can solve simultaneously and provide endogenous natural gas and electricity projections to enhance decision making on both markets [26].

NANELM splits the continent into 19 regions: 13 in the US, 5 in Mexico, and Canada. For both the US and Mexico, NANELM regions are aggregated to reflect identical groupings of regions within both the US Energy Information Administration and Mexico's Secretaria de Energia [6][8]. Even though the regions are not as precise as every state or province in North America, the level of detail still gives significant insights on the future of generation, consumption and transmission of electricity on the continent. All the data used in NANELM originates from 2016 databases from EIA and SENER [6][8]. Figure 3 and 6 show 13 regions in the US and the 5 in Mexico with 1 other remaining representing Canada.

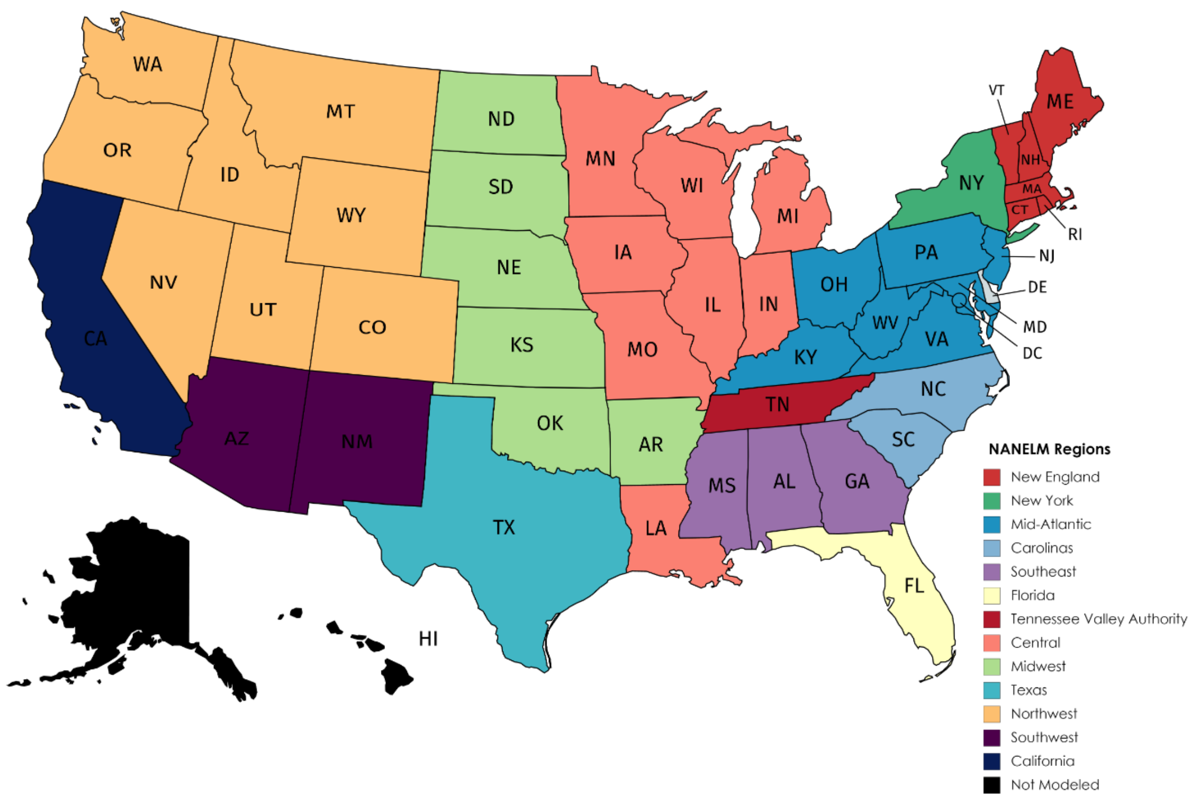


Figure 5: NANELM US Regions

Figure 6: NANELM Mexican Regions [24]

Each region has its own generation mix and NANELM aggregates its generation capacity into 15 different generation types:

Table 1: NANELM Generation Types

Generation Type	NANELM Abreviation
Conventional Steam Coal	COALF
Petroleum Liquids	OILF
Natural Gas Fired Combined Cycle	CCGF
Natural Gas Fired Combustion Turbine	CTGF
Natural Gas Steam Turbine	STGF
Nuclear	NUCF
Wood/Wood Waste Biomass	BIOF
Conventional Hydroelectric	AHYD
Onshore Wind Turbine	WIND
Solar Photovoltaic	PV
Geothermal	GTHM
Cogeneration	COGEN
Fluidized bed	FB
Solar Thermal	ST
Kinetic Energy	KE

The data for this model can be separated in four different categories:

1. Supply (Electricity Generation)
2. Demand (Electricity Consumption)
3. Trade (Electricity Transmission)
4. Policies (Energy Policies)

3.1 Supply

Although not every generation and technology type is represented in NANELM, the model includes 15 different generation types that cover 97.2% of the US generation mix and 99.2% of the Mexican generation mix [6]. Canada is a net exporter of electricity to the US and is modeled as a production node, connected to the four regions in the US. For NANELM's 15 different technology types, the model takes into account generation capacity, heat rates, fuel costs, fixed investment costs, and operations and maintenance costs for each individual plants reported in EIA and SENER [6] [8]. The individual plants are then aggregated into the 19 different regions and modeled as 19 different production nodes with different generation mixes and different costs. The model determines regional production based on regional cost of production (marginal and fixed), and production capacity.

3.2 Demand

Similar to the supply, the hourly demand is aggregated into 19 different regions in NANELM. Instead of clearing the energy market for every hour, the annual consumption is aggregated and sorted into a load duration curve (Figure 7) and separated into 11 equally incremented segments for every year (Figure 8). Below is an example of the load duration curve for New York State.

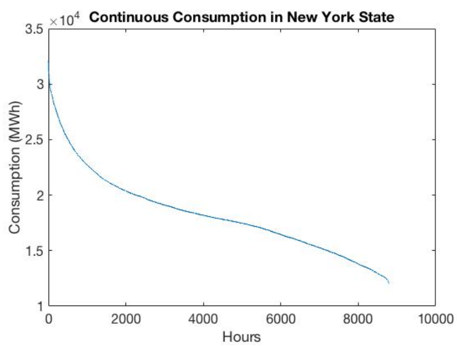


Figure 7: Continuous Load Duration Curve for NY

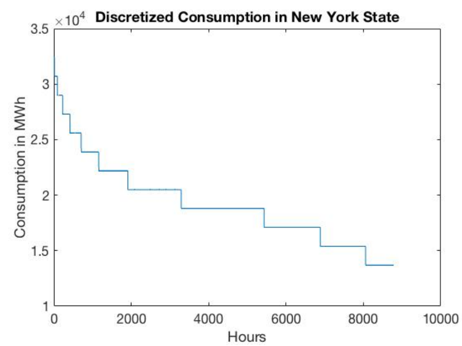


Figure 8: Discretized Load Duration Curve for NY

In addition to modeling the demand in each time segment. The change in demand from 2016-2050 is modeled exogenously by extracting the demand forecast from EIA's Annual Energy Outlook and SENER [6] [8].

3.3 Trade

Instead of modeling individual transmission lines, trade is modeled as regions sending power to other regions. The aggregate transmission capacity is summed over the region to other regions and each region-to-region capacity was found through EIA [6]. NANELM uses the fixed investment costs per megawatt-mile provided by the Western Electricity Coordinating Council database [10].

3.4 Policies

The state-level renewable portfolio standard are modeled alongside the physical portions of the market to represent current energy policies. Of all the renewable energy policies, Renewable Portfolio Standards data is the one type of energy policy that is comprehensive across all regions in the model [35]

3.5 Sets, Parameters, Variables

Variables in the model are described in all upper case (VAR) and sets, parameters, and known values in the model are described in lower case (par).

3.5.1 Sets

Set Name	Set Descrption
tec	All Electricity Producing Technologies
reg	North American Regions
t	Model Time Periods
tsg	Model Time Segments of Each Year

3.5.2 Parameters

Variable Name	Variable Description	Variable Sets	Variable Units
map_reg	Regional Connectivity (to region, from region)	reg,regg	Binary
auf	Reference Availability Utilization Factor of Technology	tec	Percentage
rsrv	Reserves Requirements at Region	reg,t	MWh
dur	Time Duration of Time Segment	tsg	hours
rps	Renewable Portfolio Standards at Region	reg,t	Percentage
cap_pow	Power Capacity Limit: of technology	tec,regg	MW
cap_ene	Energy Capacity Limit: of technology	tec,regg,t	MWh
cap_flow	Base year Transmission Capacity Limit: Flow at region	reg,regg	MW
dem_ele	Reference Demand for Electricity	(regg,tsg,t)	MWh/h
dem_cng	Change in Consumption of Region w.r.t. 2016	reg,t	percentage
c_trp	Cost of Transporting Electricity (to region, from region)	reg,regg	$\frac{\$}{MWh}$
cpr_tec	Model Cost of Technology	reg,tec,tsg,t	$\frac{\$}{MWh}$
cpr_tec_low	Model Cost of Technology with Low Gas Price	reg,tec,tsg,t	$\frac{\$}{MWh}$
cpr_tec_high	Model Cost of Technology with High Gas Price	reg,tec,tsg,t	$\frac{\$}{MWh}$
fc_tec	Reference Investment Cost for Technology	tec,reg	$\frac{\$}{MW}$
fc_trp	Reference Investment Cost for Line at region	reg,regg	$\frac{\$}{MW}$

3.5.3 Variables

Variable Name	Variable Description	Variable Sets	Variable Units
LMP	Locational Marginal Price	reg,tsg,t	$\frac{\$}{\text{MWh}}$
QEXP_POW	Exports of Electricity from Region	reg,tsg,t	MWh
QIMP_POW	Imports of Electricity to Region	reg,tsg,t	MWh
QC_POW	Power Consumption	reg,tsg,t	MW
QC_ENE	Energy Consumption	reg,tsg,t	MWh
RNT_POW	Rent of Capacity for Power Production of Technology	tec,regg,tsg,t	$\frac{\$}{\text{MW}}$
RNT_ENE	Rent of Capacity for Energy Production of Technology	tec,regg,t	$\frac{\$}{\text{MWh}}$
RNT_RSRV	Rent of Reserves Requirements	regg,tsg,t	$\frac{\$}{\text{MW}}$
RNT_FLOW	Rent of Capacity Limit of Flow at region	reg,regg,tsg,t	$\frac{\$}{\text{MW}}$
RNT_RPS	Rent of meeting Renewable Policy Standards of Region	reg,t	$\frac{\$}{\text{MW}}$
POW	Power Production of Technology	tec,regg,tsg,t	MW
QFLOW	Power Flow to Region	reg,regg,tsg,t	MWh
INV_TEC	New capacity for Technology	tec,regg,t	MW
INV_TRP	New Capacity for Line at Region	reg,regg,t	MW

3.6 Complementarity Formulation

3.6.1 Producers

1. KKT condition for the marginal production for producers ($\forall tec, reg, tsg, t$)

$$\begin{aligned} 0 \leq POW(tec, reg, tsg, t) \perp \big[&cpr\_tec(tec, regg, tsg, t) + RNT\_POW(tec, regg, tsg, t) \\ &+ dur(tsg)RNT\_ELE(tec, regg, t) + dur(tsg)rps(reg, t)RNT\_RPS(reg, t) \\ &- LMP(reg, tsg, t)\big] \geq 0 \end{aligned}$$

2. KKT condition for the technology capacity expansion for producers ($\forall tec, reg, t \in vnt$)

$$\begin{aligned} 0 \leq INV\_TEC(tec, regg, t) \perp \sum_{t \in vnt} fc\_tec(reg, regg, tsg, t) &- \sum_{tsg, t \in vnt} auf(tec, reg, tsg, t)RNT\_POW(reg, regg, tsg, t) \\ &- \sum_{tsg, t \in vnt} auf(tec, reg, tsg, t)RNT\_RSRV(reg, tsg, t) \geq 0 \end{aligned}$$

3. Power Capacity

$$0 \leq RNT\_POW(tec, regg, tsg, t) \perp \Bigg[\sum_{t}(auf_{reg,tec,tsg,t})(cap\_pow_{reg,tec}) + \sum_{t \in vnt}(auf_{tec,reg,tsg,t})(INV\_TEC_{reg,tec,t}) - \sum_{t} POW_{reg,tec,tsg,t}\Bigg] \geq 0$$

4. Total consumption of power at region ($\forall reg, tsg, t$)

$$0 \leq QC\_POW(reg, tsg, t) \perp \left[QC\_POW(reg, tsg, t) - dem\_ele(reg, tsg, t)\right] \geq 0$$

5. Total consumption of energy at region ($\forall reg, t$)

$$0 \leq QC\_ENE(reg, t) \perp \left[QC\_ENE(reg, t) - \sum_{tsg}(QC\_POW(reg, tsg, t)\right] \geq 0$$

6. Energy Capacity ($\forall tec, reg, t$)

$$0 \leq RNT\_ENE(tec, regg, t) \perp cap\_ene(tec, reg, t - \sum_{tsg}(dur_{tsg})(POW(tec, reg, tsg, t)) \geq 0$$

7. Energy Reserves ($\forall reg, tsg$)

$$0 \leq RNT\_RSRV \perp \sum_{tec}\sum_{t} auf(tec, reg, tsg, t)cap\_pow(tec, reg) + \sum_{tec}\sum_{t} auf(tec, reg, tsg, t)INV\_TEC(tec, reg) - dem\_ele(reg, tsg, t)(1 + rsrv(regg, t)) \geq 0$$

8. Renewable Energy Portfolio ($\forall reg, t$)

$$0 \leq RNT\_RPS(tec, reg, t) \perp \sum_{tec \in rtec}\sum_{tsg} dur(tsg)POW(tec, reg, tsg, t) - rps(reg, t)\left(\sum_{tec}\sum_{tsg} dur(tsg)POW(tec, reg, rsg, t)\right) \geq 0$$

3.6.2 Transporters

9. KKT condition for marginal transmission for transporters ($\forall reg, regg, tsg, t$)

$$0 \leq QFLOW(reg, regg, tsg, t) \perp c\_trp(reg, regg, tsg, t) + RNT\_FLOW(reg, regg, tsg, t) + (LMP(reg, tsg, t) - LMP(regg, tsg, t)) \geq 0$$

10. KKT Condition for the line capacity expansion for transporters ($\forall reg, regg, t \in vnt$)

$$0 \leq INV\_TRP \perp \sum_{t \in vnt} fc\_trp(reg, regg, tsg, t) - \sum_{tsg, t \in vnt} RNT\_FLOW(reg, regg, tsg, t) \geq 0$$

11. Exports of electricity from region ($\forall reg, tsg, t$)

$$QEXP\_POW(reg, tsg, t) - \sum_{reg \in map\_reg} QFLOW(reg, regg, tsg, t) = 0$$

$$QEXP\_POW(reg, tsg, t) \text{ is free}$$

12. Imports of electricity from region ($\forall reg, tsg, t$)

$$QIMP\_POW(reg, tsg, t) - \sum_{reg \in map\_reg} QFLOW(regg, reg, tsg, t) = 0$$

$$QIMP\_POW(reg, tsg, t) \text{ is free}$$

13. Flow Capacity ($\forall reg, regg$)

$$0 \leq RNT\_FLOW(reg, regg, tsg, t) \perp dur(tsg) cap\_flow(reg, regg) + dur_{tsg} \sum_{t \in vnt} \Big(INV\_TRP_{reg,regg,t} + INV\_TRP_{regg,reg,t} \Big) - QFLOW(reg, regg, tsg, t) \geq 0$$

3.6.3 Market Clearing for the System

14. Energy balance ($\forall reg, tsg, t$)

$$\sum_{tec \in mreg\_prd} (POW_{reg,tec,tsg,t}) - QC\_POW_{reg,tsg,t} - \sum_{reg \in map\_reg} (QFLOW_{reg,regg,tsg,t}) + \sum_{reg \in map\_reg} (QFLOW_{regg,reg,tsg,t}) - Q^{EXP,POW}_{reg,tsg,t} + Q^{IMP,POW}_{reg,tsg,t} = 0$$

$$LMP(reg, tsg, t) \text{is free}$$

4 Price Shock Scenarios

To simulate the volatility of natural gas prices, the model runs four types of price shock scenarios as seen in Table 2. Each of the four scenarios is taken from the US Energy Information Administration's Annual Energy Outlook [27]. To simulate the price changes, the fuel costs for natural gas producers either experience a spike or drop in price after 2030. This is modeled by multiplying a percentage increase/decrease each year after 2030 for the marginal cost of gas. For the high renewable portfolio standard, a similar strategy is employed. Current levels of renewable standards for each region and year are multiplied by a percentage increase, reflecting the high renewable portfolio standard scenario.

Table 2: Price Shock Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Low Gas Price	Yes	No	Yes	No
High Gas Price	No	Yes	No	Yes
High RPS	No	No	Yes	Yes
Fixed Investment Up to 2030	Yes	Yes	No	No

4.1 Baseline and Reference Case

To measure the model results, a baseline case is needed to assess the system's resiliency under these scenarios. This case is a business-as-usual case with the current generation, consumption and transmission schemes along with the existing energy policies in place. NANELM's base case is calibrated with the data from US Energy Information Administration, Mexico's Energy Secretaria de Energie, and Canada's National Energy Board.

NANELM is equipped with the necessary features to provide insight on the progression of electricity infrastructure development. The calibration process focuses on accurately representing regional generation mix, future capacity investment in generating plants and transmission lines, and the net transmission between the regions. The calibration process for both players in the market, transmission operators and plant operators, requires manual adjustments to their respective marginal, fixed, and investment costs, and capacity parameters.

4.2 Scenario 1: Low Gas Price

With new techniques increasing the ability to recover raw natural gas, the past decade has seen the energy industry reacting to the sudden influx of cheap natural gas. This increase in supply is projected to play a role, but the availability of natural gas may change over the next few decades [27].

In this particular scenario, the availability of natural gas supply increases after 2030. This scenario depicts new technological advances in drilling, production, and even experimentation in natural gas refinement that allow for an increase in natural gas relative to the reference case. With the extra supply of natural gas, the price in this scenario after 2030 drop at most to 20% relative to the base case [27].

In order to compare it to the baseline scenario, we fix the investments to all energy infrastructure from 2016 up to 2030. This can be seen in Figure 9, showing the percentage increase and decrease in natural gas prices relative to the base case.

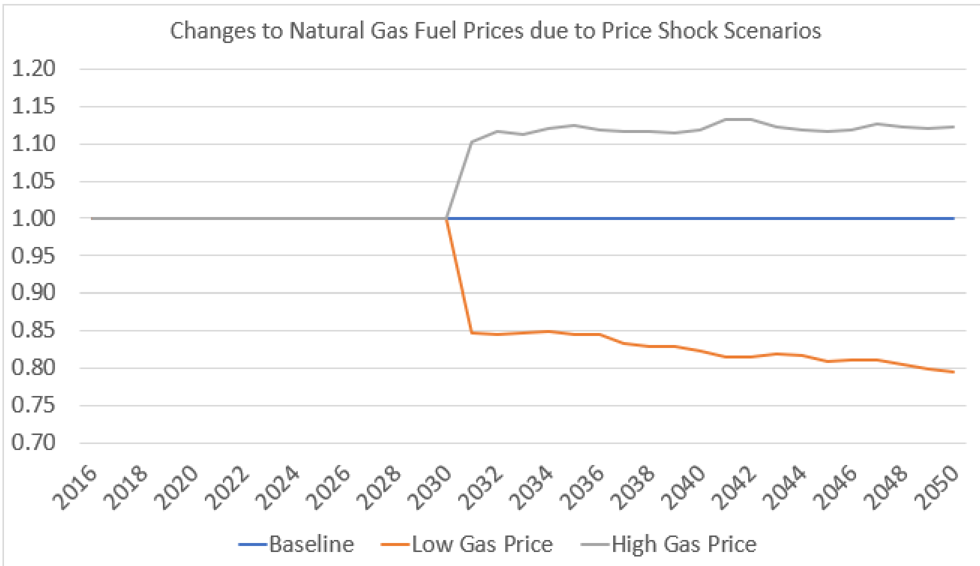


Figure 9: NANELM Gas Price Shock Scenarios: High and Low Scenarios

4.3 Scenario 2: High Gas Price

Unlike the previous scenario, the low gas supply scenario assumes a decrease in natural gas supply which corresponds to a drop in price. This scenario depicts the forecast of natural gas supply to be bleaker than imagined with the prices increasing to 12% above the reference case starting in 2030 [27]. Similar to the previous scenario, we fix the investments to all energy infrastructure from 2016 up to 2030.

4.4 Scenario 3+4: High/Low Gas Price + High Renewable Portfolio Standard

In addition to the fluctuations in gas supply, renewables are coming online at a high rate due to clean energy policies and climate change. This scenario assumes 20% of all electricity production originates from renewable energy sources by 2020 and 50% by 2050. This increase in renewable production is enforced by a percent change to the existing renewable portfolio standard in each region and can be seen in Equation 8 in the model formulation. Therefore, regions with existing renewables energy goals will see an increase in their RPS. On the other hand, the regions with little to no renewables generation mandates will not be affected, but the overall system RPS reaches 20% by 2020 and 50% by 2050.

This high RPS scenario combined the high and low gas price scenarios with high renewable portfolio standards (RPS) completes the four total price shock scenarios for this model. Here, the investment is not fixed to the baseline scenarios because additional investment in renewables is required prior to 2030.

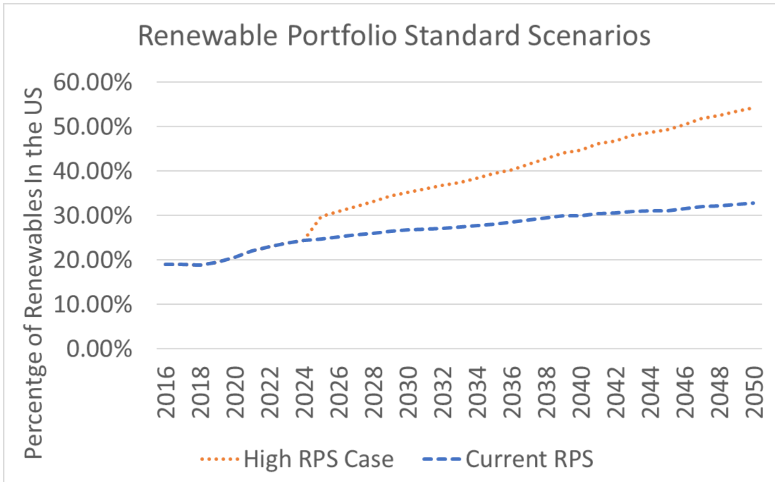


Figure 10: NANELM Renewable Portfolio Standard: High and Current Scenarios

5 Results and Discussion

5.1 Baseline

For this study, the baseline is the business-as-usual scenario with no price shocks. All resiliency metrics will use this scenario as to their baseline. In addition to the resiliency metric, NANELM shows how producers and transmission operators react under all scenarios.

Figure 11 shows the baseline net transmission and the regional marginal prices for each region in 2030 to illustrate how each region in the US interact with each other without any disturbance to the price of natural gas. Each scenario is compared to the baseline flows in 2030, the year that the shocks are introduced. The arrows in the figure represent the net flows from one region to another, but not all net flows in the system are present. Subsequent flow charts will be represented as a percentage of the original flow. For example, 100% indicates that the flows in a scenario maintain 100% of the baseline flows.

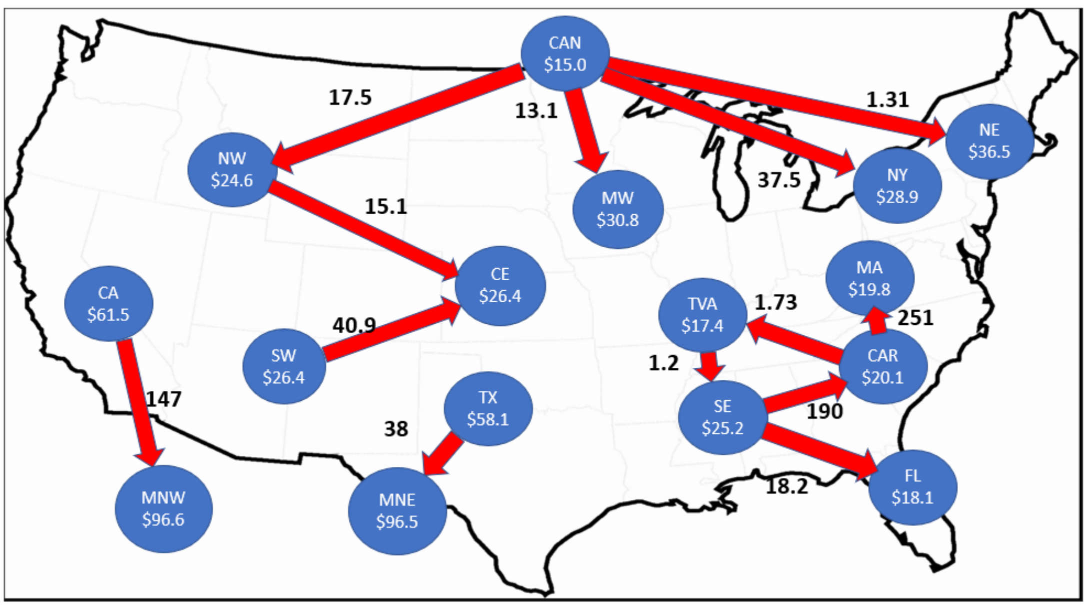


Figure 11: Base Case Net Transmission (in TWh) and Locational Marginal Prices (in $\frac{\$}{\mathrm{MWh}}$) in 2030

Using the resiliency metric described in Equation 1 and 2, the system's ability to recover from the sudden change in natural gas price can be measured across all scenarios. As seen in Figure 12, the total system costs vary across all regions relative. Other than the low gas price scenario, the other three scenarios see an increase in system cost.

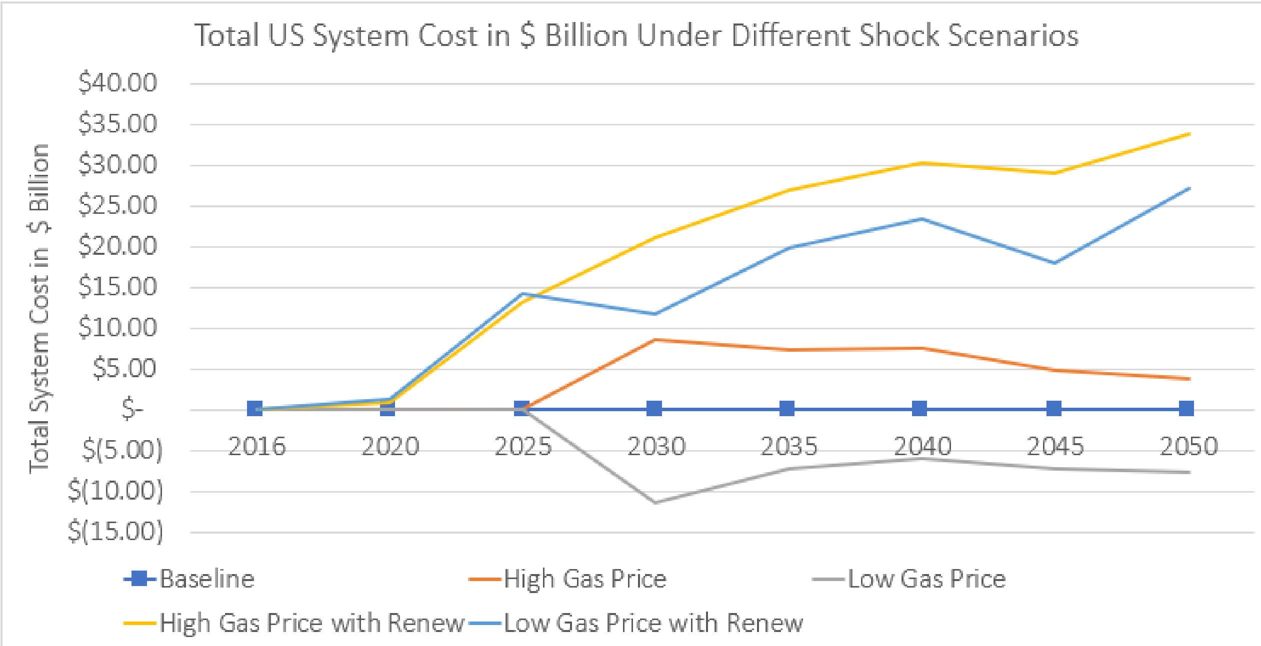


Figure 12: Total US System Deviation in $ Under Different Shock Scenarios

This increase in system cost can be seen in Figure 13. The two gas price shock only scenarios show fewer perturbations than the high renewable scenarios.

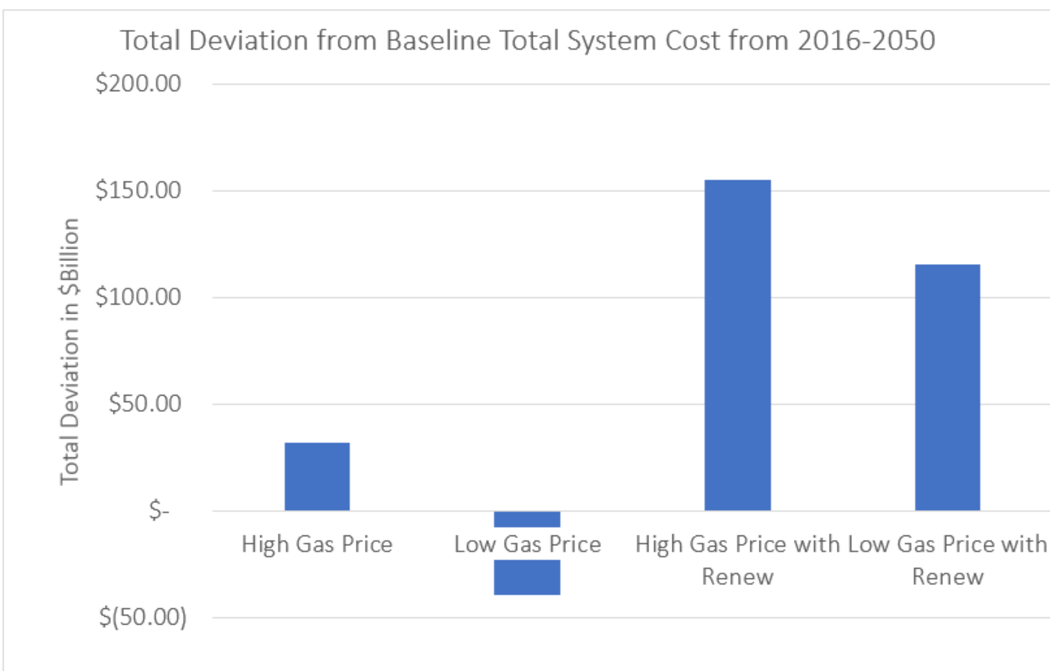


Figure 13: Total US System Cost from 2016-2050 Under Different Shock Scenarios (R_{scen})

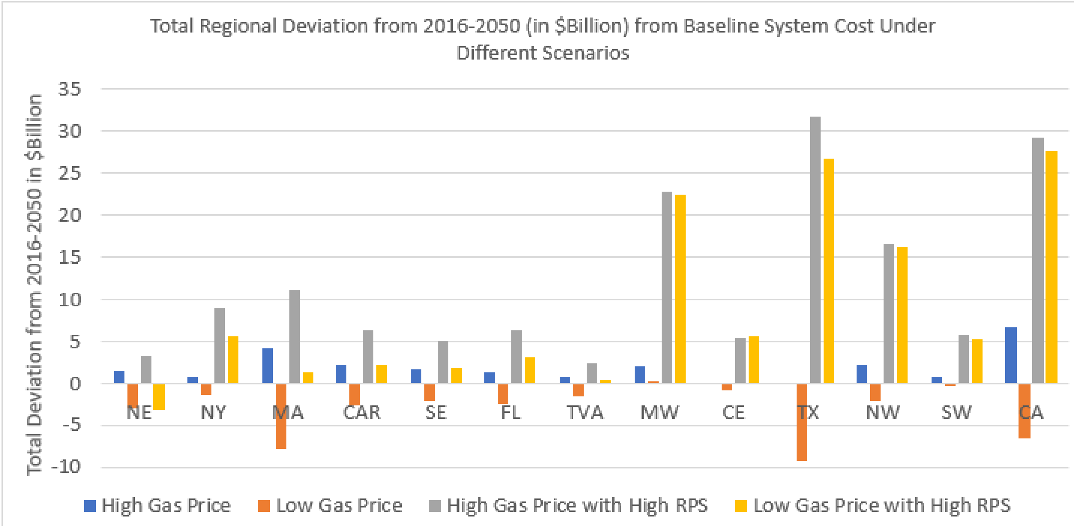


Figure 14: Total Regional System Cost from 2016-2050 Under Different Shock Scenarios ($R_{scen}(reg)$)

Figure 14 shows that the lower a region's cost deviates from the base case, the more resilient the region is. For example, New England and New York appear to be more resilient than California or Texas. This will be further discussed in individual scenarios. In addition to witnessing the volatility in LMP for each scenario, the differences in investment are also key in understanding how each region recovers after the shock in supply.

5.2 Scenario 1: Low Gas Price

Given that the natural gas fuel cost falls so abruptly in this scenario, it is clear that the regions with existing higher gas capacity benefit from this increase in natural gas supply in the short term. The marginal cost of electricity produced by natural gas drops, and regions with high natural gas plant capacities are able to meet demand at a lower cost. Regions like the Carolinas reap immediate benefits and increase their production by 4% in 2030 and up to 17% by 2040. Notably, this price drop encourages regions like New England, the Southwest and the Mid-Atlantic to invest in new natural gas capacities.

As some regions increase their production capacities, others like Tennessee Valley and the Southeast decrease their electricity production and decide to import from regions with increased electricity production from natural gas power plants. As seen in Figure 15, Tennessee's net import grew to over 1200% of the baseline flows in 2030. This is due to the change in regional prices. Under these new conditions, Tennessee's regional electricity price across hours of the year is not competitive relative to the Carolinas' regional price of electricity; therefore, Tennessee imports more than it would during the baseline case.

Unsurprisingly in this scenario, most regions show a decrease in system cost due to the sudden influx of

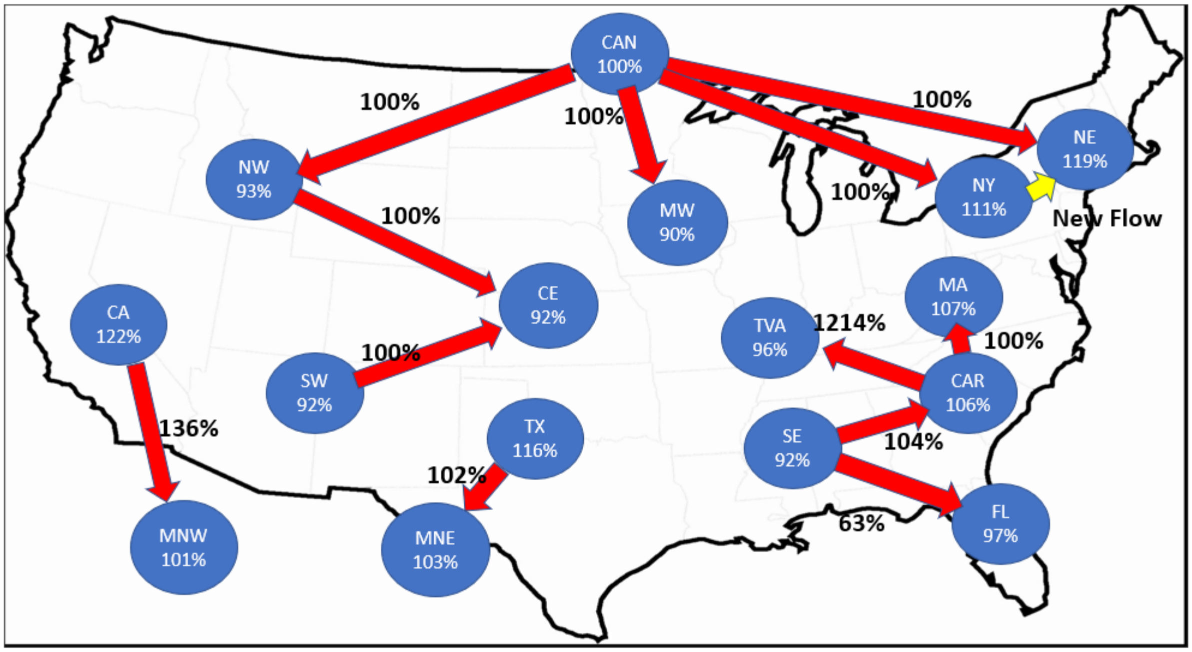


Figure 15: 2030 Ratios of Low Gas Price vs. Baseline Scenario LMPs and Transmission

gas supply. Figure 14 shows the deviations in system costs in billions of dollars from the baseline for each region in the US (See Equation 1). It is clear that some regions have higher sensitivity to the price shock than others.

Looking at the the total deviation from the baseline case, all regions reduce their overall system costs, some more than others. Regions with higher natural gas capacities or regions that are connected to other regions with higher natural gas capacities benefit the most. Cheaper gas prices result in an increase of natural gas capacity across the east coast of the US along with lower locational marginal prices. Almost immediately after the shock, a surge of natural gas investment increases, padding the natural gas contribution to the fuel mix to over 50% at 2050. This scenario reduces the total system cost by $33 billion between 2016-2050, as seen in Figure 13. Ultimately, this scenario's total system cost never recovers to the baseline system cost, but in this case, the system cost is lowered and the market players are spending less than they would at the baseline case.

5.3 Scenario 2: High Gas Price

With a higher gas prices, the same regions that benefited from lower gas prices show the opposite reaction to this scenario. Regions like the Southeast, the Carolinas, New England, and the Southwest see a decrease in production ranging from a 9% decrease in New England production in 2040 to a 30% decrease in the Southwest production. However, it would be wrong to assume that regions with high levels of natural gas

Regional Total Deviation from Baseline in $ Billion													
Scenario	**NE**	**NY**	**MA**	**CAR**	**SE**	**FL**	**TVA**	**MW**	**CE**	**TX**	**NW**	**SW**	**CA**
High Gas Price	$ 1.48	$ 0.84	$ 4.27	$ 2.22	$ 1.76	$ 1.36	$ 0.72	$ 2.05	$ (0.01)	$ -	$ 2.22	$ 0.73	$ 6.62
Low Gas Price	$ (3.00)	$ (1.43)	$ (7.73)	$ (2.60)	$ (2.02)	$ (2.44)	$ (1.57)	$ 0.06	$ (0.80)	$ (9.28)	$ (2.05)	$ (0.32)	$ (6.48)
High Gas Price with High RPS	$ 3.37	$ 8.99	$ 11.13	$ 6.36	$ 5.09	$ 6.27	$ 2.38	$ 22.78	$ 5.45	$ 31.67	$ 16.61	$ 5.73	$ 29.31
Low Gas Price with High RPS	$ (3.07)	$ 5.65	$ 1.29	$ 2.25	$ 1.87	$ 3.16	$ 0.46	$ 22.49	$ 5.55	$ 26.75	$ 16.18	$ 5.34	$ 27.54

Recovery Time in Years (NR = Never Recovered)													
Scenario	**NE**	**NY**	**MA**	**CAR**	**SE**	**FL**	**TVA**	**MW**	**CE**	**TX**	**NW**	**SW**	**CA**
High Gas Price	NR	0	NR	NR	NR	10	0	0	0	5	15	10	20
Low Gas Price	0	0	0	0	0	0	0	0	0	5	0	0	0
High Gas Price with High RPS	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Low Gas Price with High RPS	0	20	0	0	0	NR	0	NR	NR	NR	NR	NR	NR

Figure 16: Percentage Change of Production in Each Region Under Low Gas Supply Scenario

generation will see decreases in their production, since regional connectivity also play a role in maintaining production.

Both Texas and the Mid-Atlantic have high natural gas plant capacities and yet they are able to maintain similar levels production because of meeting neighboring region's electricity demand. Regardless of the hike in gas prices, Texas still trades at similar levels with Mexico despite the higher locational marginal price and Mid-Atlantic maintains its total production by shifting their generation to other technology types. The Mid-Atlantic benefits from having old coal plants and expanding renewables to help the lack of natural gas production.

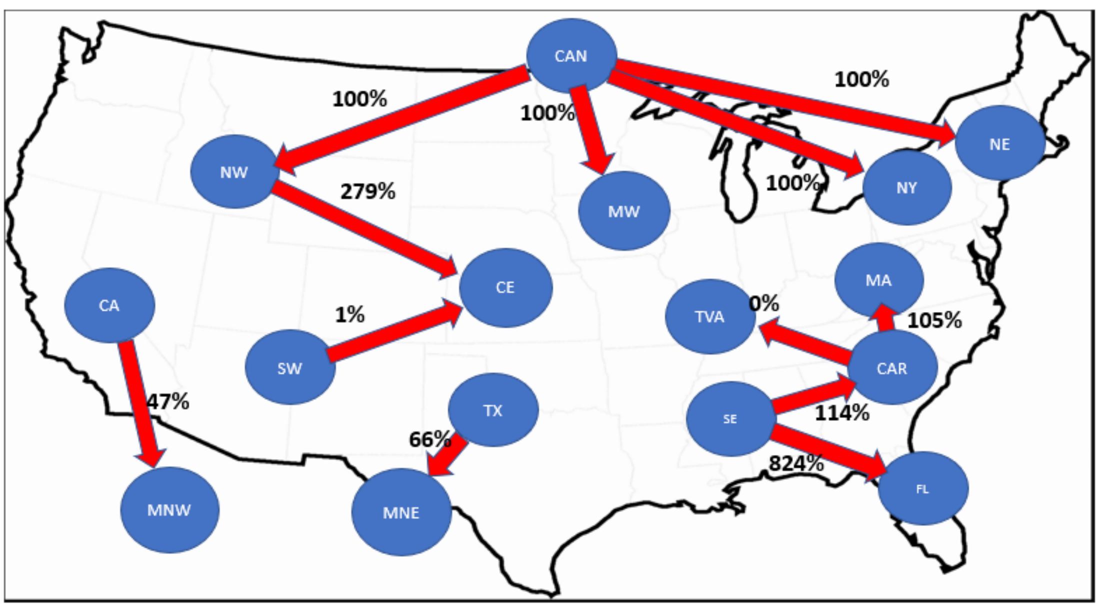


Figure 17: 2030 Ratios of High Gas Price vs. Baseline Scenario LMPs and Transmission

The regions with less reliance on natural gas end up having to produce more to make up for demand to transmit to others. Regions like California, Tennessee, and New York see an increase in production relative to the base case because of their other generation capacities. For Tennessee, existing coal and oil fired plants need to run at higher capacity to cover the base load for other regions like the Southeast. Though coal is a traditional base load plant, oil is not traditionally used often due to its high fuel cost. It is important to note that no investments in new capacity for neither coal nor oil were made in this scenario.

For New York and California, increased production is a combination of existing and newly invested renewable capacity that allows for more production. New York invests in more wind and California invests in more solar.

Overall, the system cost increases by almost two times the system cost to $30 billion across all regions. Natural gas plant expansion comes to a halt at 2030 and existing coal and oil plants pick up the slack. Though some regions bounce back within 15-20 years after the price shock, this scenario's total system cost never returns to the baseline, leaving a higher price of electricity for the next 20 years after the price shock.

5.4 Scenario 3: Low Gas Price with High Renewables

This scenario includes conflicting forces. On the one hand, the addition of renewables increases the marginal cost of electricity across all regions as the new capacities come into play; but on the other, the decrease in prices mitigates the damage. This is evident when observing the locational marginal prices in Figures E.8. For the most part, regions see an increase in locational marginal prices and tend to stay higher throughout the scenario. However, some regions like New York, Texas and New England recover or come close to it. Their ability to recover is evident in their production over the next few years.

New York, Texas and New England are the few regions that increase its production. New England trims their natural gas electricity production and increases its renewable energy production, mainly in wind and solar. Unlike New England, Texas' renewable and gas investments both soar. This is due to increased trade cross border to Mexico's Northeastern region. However, Texas and New England do not recover but they fare better than other regions that settled at a higher cost equilibrium. New York is the only region that recovers to the baseline case.

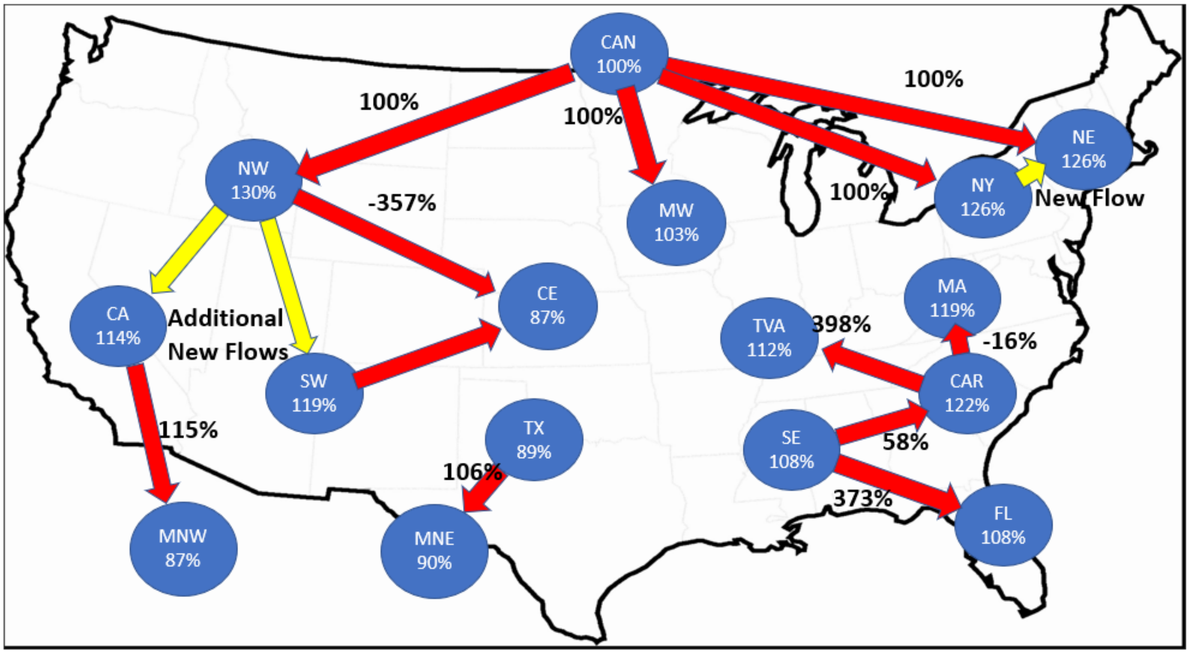


Figure 18: 2030 Ratios of Low Gas Price with High Renewables vs. Baseline Scenario LMPs and Transmission

In terms of transmission, Figure 15 shows that there are reversals in directions of net transmission under this scenario, notably, between the Northwest region and the Central region. Due to the high encouragement to inest in renewables combined with the already strict renewable energy mandates in Central, the high RPS jolted investment in renewables, resulting in an average decrease in LMPs in 2030 and reversing the direction of net flows between Central and the Northwest.

Similarly, the Carolinas and Mid-Atlantic also switch direction due to the increase of gas supply in the Mid-Atlantic. The Mid-Atlantic is one of the few regions in the US yet to have a high RPS. In this scenario, the Mid-Atlantic expands its natural gas capacity without strict renewable mandates like its neighbors. In fact, it trims out coal production after 2035 and invests in new natural gas power plants. In addition to the RPS increasing the rise of renewables, Figures D.4 and D.7 shows a dramatic dip in coal and natural gas coming online.

Overall, the cost of adding renewables this increases the system cost. For most regions, that increase of marginal cost returns down to the baseline, meaning that the system does not have the ability to change courses back to the baseline scenario once it is perturbed. That being said, the low gas price still results in a lower change in system cost than the high gas scenario with a change of $14 trillion over the course of 20 year shock.

5.5 Scenario 4: High Gas Price with High Renewables

It is no surprise that this scenario would create the largest deviations from the baseline scenario. Not only are the regions trying to reach their renewable energy goals and invest in new renewable capacities to meet mandates, but natural gas prices sharply increase. One can see in the LMP figure (Fig. E.8) that each region's locational marginal price jumps up and it rarely finds a way back down to the base case.

In terms of maintaining production, regions that have a variety of different fuels appear to deviate less from the baseline case. Regions like New England, the Midwest, and California see a similar output in production. On the other hand, this scenario proves to be tough on regions in the Southeast, Carolinas, and Tennessee. These regions rely heavily on neighboring regions that have the ability to provide electricity. However, the electricity produced from these other regions not from new renewables, but rather, existing coal plants.

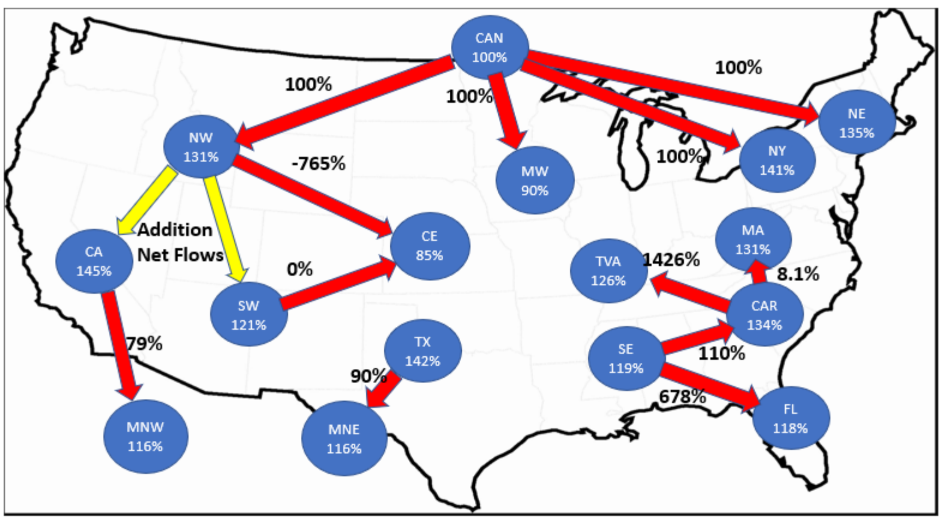


Figure 19: 2030 Ratios of High Gas Price with High Renewables vs. Baseline Scenario LMPs and Transmission

The Mid-Atlantic and the Mid-West fire up existing coal plants in 2030. There is a sudden increase in coal while renewables continue to expand due to the RPS requirements. This squeezes natural gas and even some nuclear out of the generation mix. It is important to note that even with a rise in coal production, the levels in 2030 and beyond stay very closely to the current coal production.

Overall, the system shows the largest increase in system cost across most regions under this scenario, almost a $155 billion increase from the base case. The areas that show vulnerability are regions that have low capacities of non-natural gas generation and low diversity in generation types, leaving them highly susceptible to natural gas price volatility. Unsurprisingly, the system does not return to the base level price across all regions.

6 Conclusion

Under these shock scenarios, the North American electricity market showed weakness in its ability to recover economically.

Of all the scenarios, only the low gas price scenario provided a lower system cost and the grid stabilized at a lower cost equilibrium. Cheaper gas prices resulted in the increased capacity of natural gas across the east coast of the US along with lower locational marginal prices. Although the regions do not recover, this scenario provides a lower total system costs, allowing producers and transmission operators to reduce their cost further.

With the other cases, the system never returned to the baseline case. Under the high gas price case and even the low gas with high renewables, some regions took more than 15-20 years to return to the baseline case, while others simply settled at a high locational marginal price until 2050. Even more drastically, the high gas price and high renewable portfolio standard scenario stressed regional flexibility to invest and produce electricity. All regions but Florida and New York never returned back to their original state and stayed at a high equilibrium, adjusting the total system cost by over 2.5 times the baseline scenario.

With the increased cost of natural gas, short term production shifts towards cheaper fuels like coal and nuclear, to handle the shifted load, and more petroleum plants come online to help with peak loads. Despite the price shock for natural gas, there is no capacity expansion for other non-renewables. The investment cost for both nuclear and coal is simply too high and cannot compete with the investment costs of renewables. This is particularly troubling for regions that currently rely heavily on natural gas, not only to cover the peak loads, but to cover the base loads. Regions in the Southeastern part of the US are affected more because of this reliance on gas, and transmission investments are also too expensive to lower system costs. The high cost of transmission investment hinders the ability to expand and provides minimal flexibility to the grid. Even within regions with high density load centers, the costs of building transmission lines outweigh the benefits and is not optimal decision to lower the overall system cost.

Under these scenarios, our grid shows weakness in its flexibility. These perturbations in the price of just one fuel source, send shock waves down the line indefinitely. This begs the question: what can be done to make the grid flexible?

Future work for this model will investigate the relationship between other energy commodities and their effect on marginal prices. A combination of other equilibrium models like The North American Natural Gas Model (NANGAM) or the North American Crude Oil Model (NACOM) will provide an more detailed and in depth understand on the origins of price volatility in the energy markets [24] [37].

More definition in certain regions like Canada would provide insight on their grid resiliency and comparing countries together. Another possible avenue is incorporating new electricity trends like demand response, storage, and microgrids [36].

APPENDIX

A Model Formulation

A.1 Producer's Optimization Formulation ($\forall tec$)

$$\begin{aligned} \max \quad & \sum_{reg} \sum_{tsg} \sum_{t} \big[LMP(reg, tsg, t) - (cpr\_tec(tec, regg, tsg, t) \big] POW(tec, regg, tsg, t) \\ & \qquad - \sum_{reg} \sum_{tec} \sum_{tt>t} fc\_tec(tec, reg, tt) INV\_TEC(tec, reg, tt) \\ & \qquad s.t. \end{aligned}$$

1. Power Capacity (reg, tec, tsg)

$$\begin{aligned} & \sum_{t} (auf_{reg,tec,tsg,t})(cap\_pow_{reg,tec}) \\ & \qquad + \sum_{t \in vnt} (auf(tec, reg, tsg, t))(INV\_TEC(reg, tec, t)) \qquad (RNT\_POW) \\ & \qquad\qquad - POW_{reg,tec,tsg,t} \geq 0 \end{aligned}$$

2. Total consumption of energy at region $(\forall reg, t)$

$$QC\_ENE(reg, t) - \sum_{tsg} dur(tsg)(QC\_POW(reg, tsg, t) = 0 \qquad (QC\_POW))$$

3. Energy Capacity $(\forall tec, reg, t)$

$$cap\_ene(tec, reg, t - \sum_{tsg} (dur_{tsg})(POW(tec, reg, tsg, t)) \geq 0 \qquad (QC\_ENE)$$

A.2 Transmission Operator's Optimization Formulation $\forall (reg, regg)$

$$\begin{aligned} \max \quad & \sum_{tsg} \sum_{t} \big[LMP(reg, tsg, t) - (LMP(regg, tsg, t) \big] QFLOW(reg, regg, tsg, t) \\ & \qquad - \sum_{tt>t} fc\_trp(reg, regg, tt) INV\_TRP(reg, reg, tt) \\ & \qquad s.t. \end{aligned}$$

1. Exports of electricity from region ($\forall reg, tsg, t$)

$$QEXP\_POW(reg, tsg, t) - \sum_{reg \in map\_reg} QFLOW(reg, regg, tsg, t) = 0 \qquad (RNT\_EXP\_ROW)$$

2. Imports of electricity from region ($\forall reg, tsg, t$)

$$QIMP\_POW(reg, tsg, t) - \sum_{reg \in map\_reg} QFLOW(regg, reg, tsg, t) = 0 \qquad (RNT\_IMP\_ROW)$$

3. Flow Capacity ($\forall reg, regg$)

$$\begin{aligned} & dur(tsg)cap\_flow(reg, regg) \\ & \quad + dur_{tsg} \sum_{t \in vnt} \Big(INV\_TRP_{reg,regg,t} + INV\_TRP_{regg,reg,t} \Big) \qquad (RNT\_EXP\_FLOW) \\ & \quad - QFLOW(reg, regg, tsg, t) \geq 0 \end{aligned}$$

A.3 Reserves, Market Clearing and Policies

1. Energy Reserves ($\forall reg, tsg$)

$$\begin{aligned} & \sum_{tec} \sum_{t} auf(tec, reg, tsg, t)cap\_pow(tec, reg) \\ & \quad + \sum_{tec} \sum_{t} auf(tec, reg, tsg, t)INV\_TEC(tec, reg) \qquad (RNT\_RSRV) \\ & \quad - dem\_ele(reg, tsg, t)(1 + rsrv(regg, t)) \geq 0 \end{aligned}$$

2. Renewable Energy Portfolio ($\forall reg, t$)

$$\begin{aligned} & \sum_{tec \in rtec} \sum_{tsg} dur(tsg)POW(tec, reg, tsg, t) \qquad (RNT\_RPS) \\ & \quad - rps(reg, t)(\sum_{tec} \sum_{tsg} dur(tsg)POW(tec, reg, rsg, t)) \geq 0 \end{aligned}$$

3. Total consumption of power at region ($\forall reg, tsg, t$)

$$QC\_POW(reg, tsg, t) - dem\_ele(reg, tsg, t) \geq 0 \qquad (QC\_POW)$$

B List of Regions in NANELM

Table 3: Regions in NANELM

NANELM Regions	NANELM Abrreviation	Provinces/States Included
New England	NE	ME, NH, VT, RI, CT, MA
New York	NY	NY
Mid-Atlantic	MA	PA, NJ, DE, MD, OH, WV, VA, DC, KY,
Carolinas	CAR	NC, SC
SouthEast	SE	GA, AL, MS
Florida	FL	FL
Tennessee Valley Authority	TVA	TN
MidWest	MW	MN, WI, MI, IA, IL, IN, MO, LA
Central	CE	ND,SD, NE, KS, OK, AR
Texas	TX	TX
NorthWest	NW	WA, OR, ID, MT, WY, CO, UT, NV
SouthWest	SW	AZ, NM
California	CA	CA
Mexico Northwest	MNW	Hermosillo, Cananea, Obregón, Los Mochis, Culiacán, Mazatlán,
Mexico Northeast	MNE	Juárez, Moctezuma, Chihuahua, Durango, Laguna, Río Escondido, Nuevo Laredo, Reynosa, Matamoros, Monterrey, Saltillo, Valles, Huasteca, Tamazunchale, Nuevo Laredo, Reynosa, Matamoros, Güéme
Mexico Interior	MIN	Central
Mexico Interior West	MNW	Querétaro, Tepic , Guadalajara, Aguascalientes, San Luis Potosí, Salamanca, Manzanillo, Carapan
Mexico South-Southeast	MSW	Poza Rica, Veracruz, Puebla, Acapulco, Temascal, Coatzacoalcos, Tabasco, Grijalva, Ixtepec, Lerma , Mérida, Cancún, Chetumal, Cozumel
Canada	ROW	All Canadian Provinces

C Fuel Mix Under Each Scenario

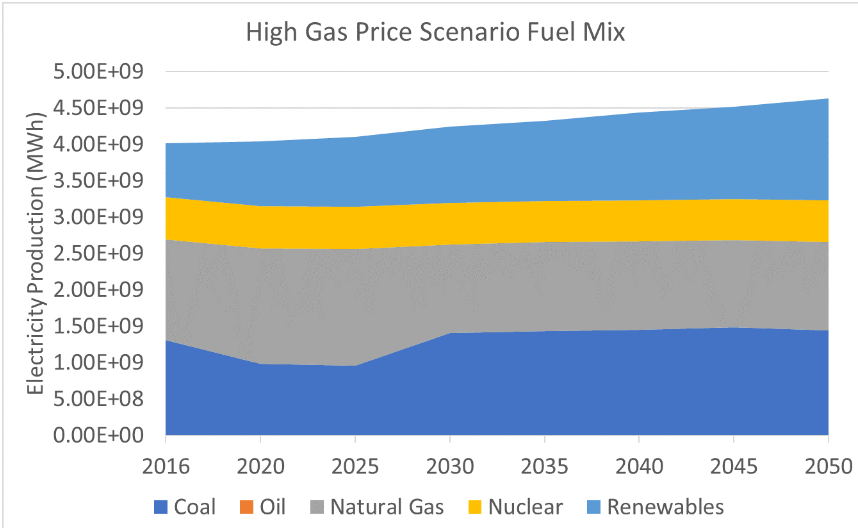
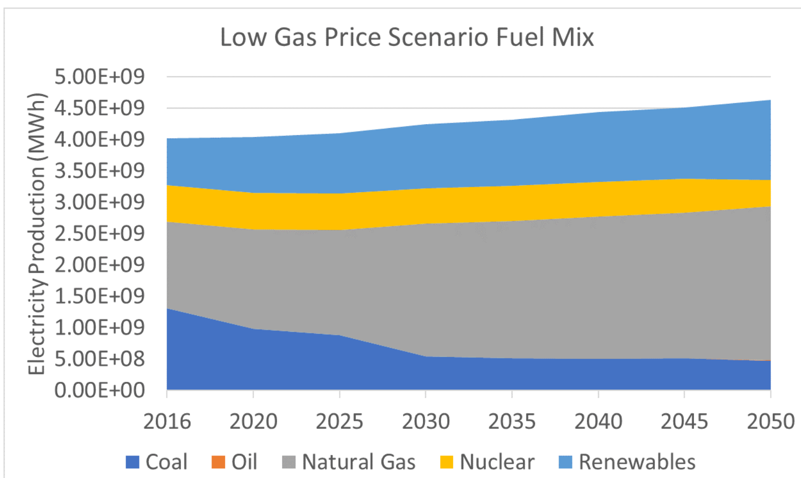


Figure C.1: 2016-2050 Fuel Mix Under High Gas Price Scenario



caption2016-2050 Fuel Mix Under Low Gas Price Scenario

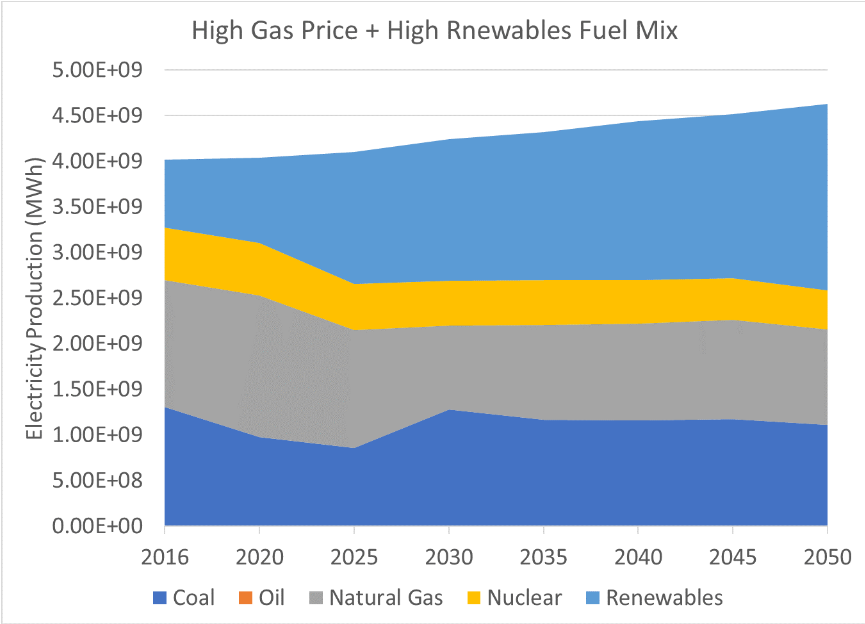


Figure C.2: 2016-2050 Fuel Mix Under High Gas Price with High RPS Scenario

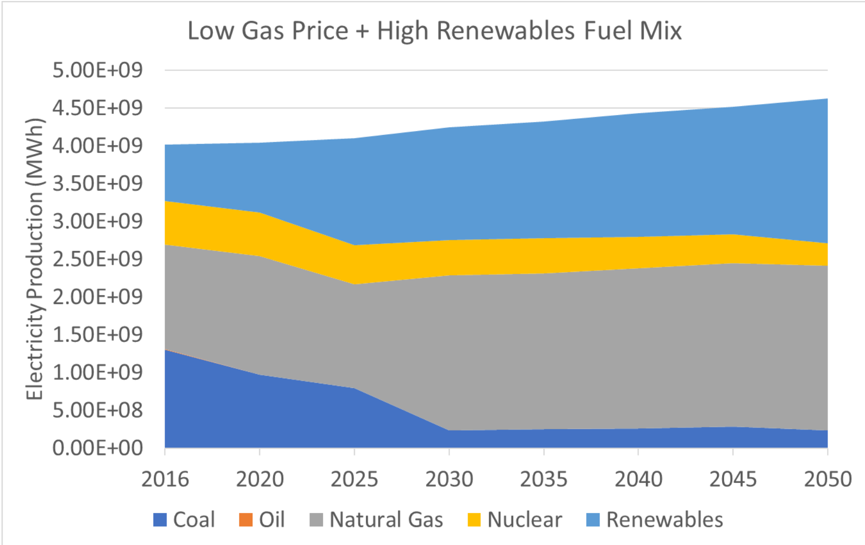


Figure C.3: 2016-2050 Fuel Mix Under Low Gas Price with High RPS Scenario

D Changes In Electricity Generation from Technology Types (in MWh) Under Different Scenarios

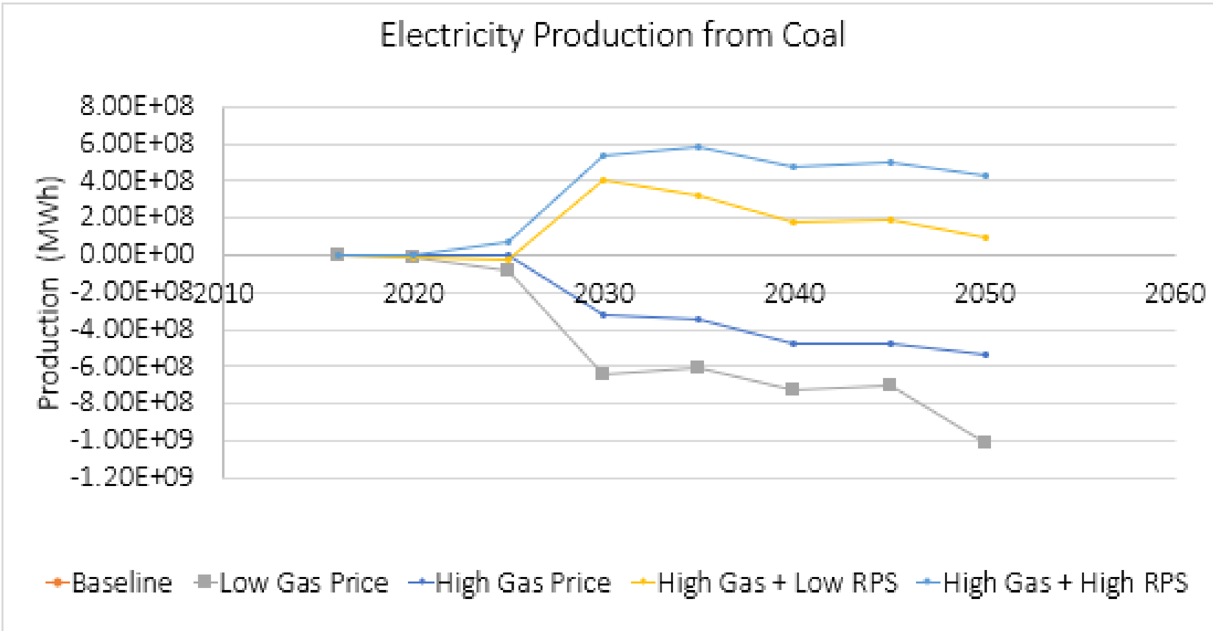


Figure D.4: Coal Production Under Shock Scenarios

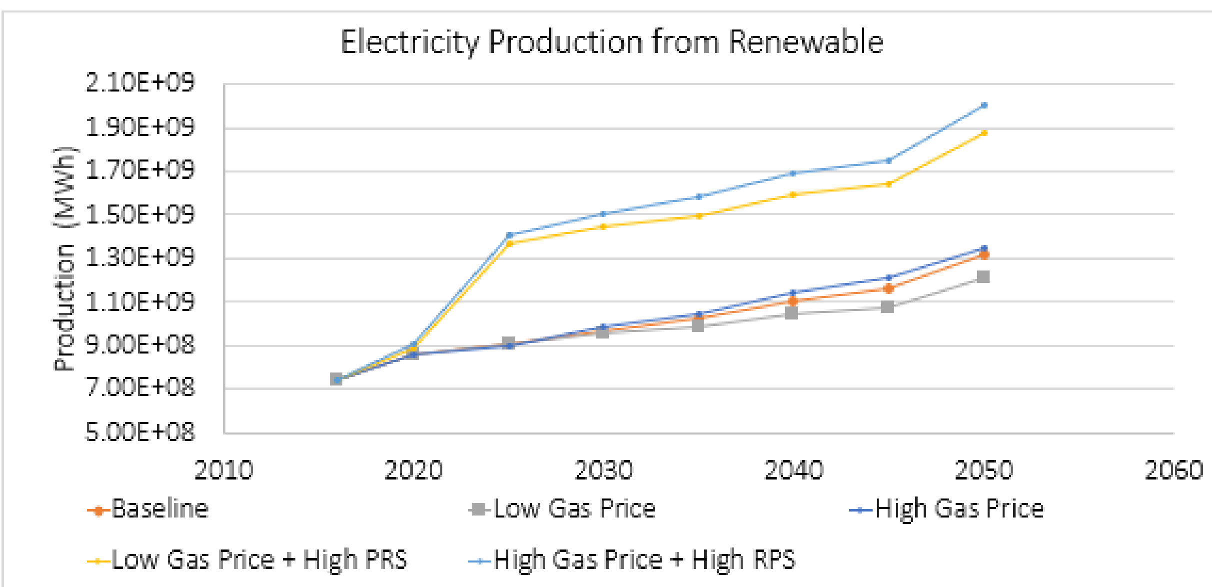


Figure D.5: New York Locational Marginal Prices

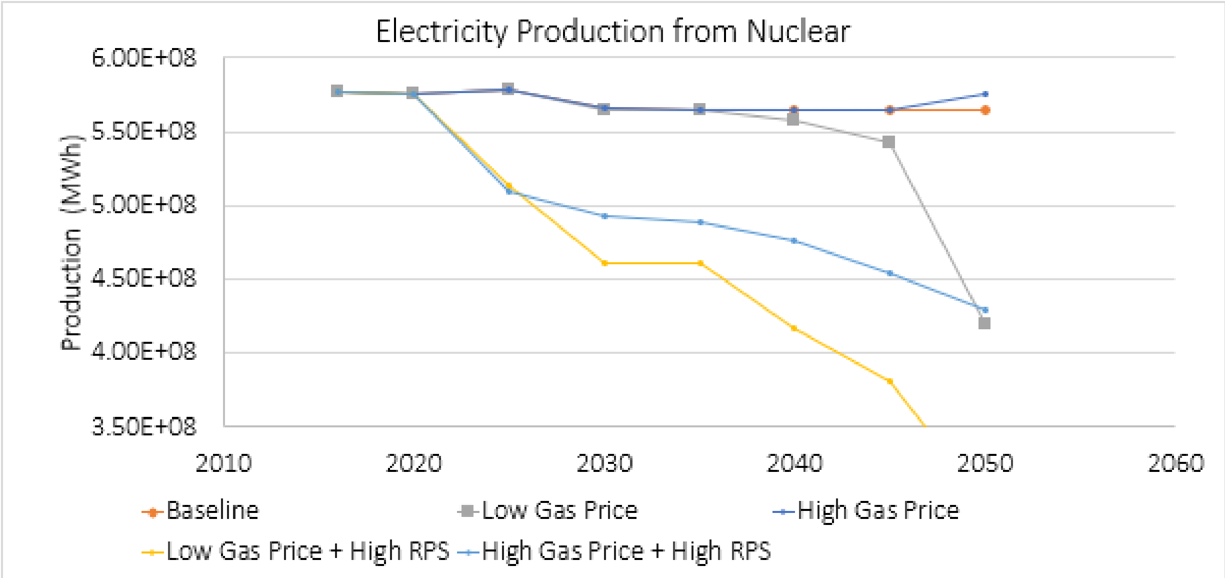


Figure D.6: Coal Production Under Shock Scenarios

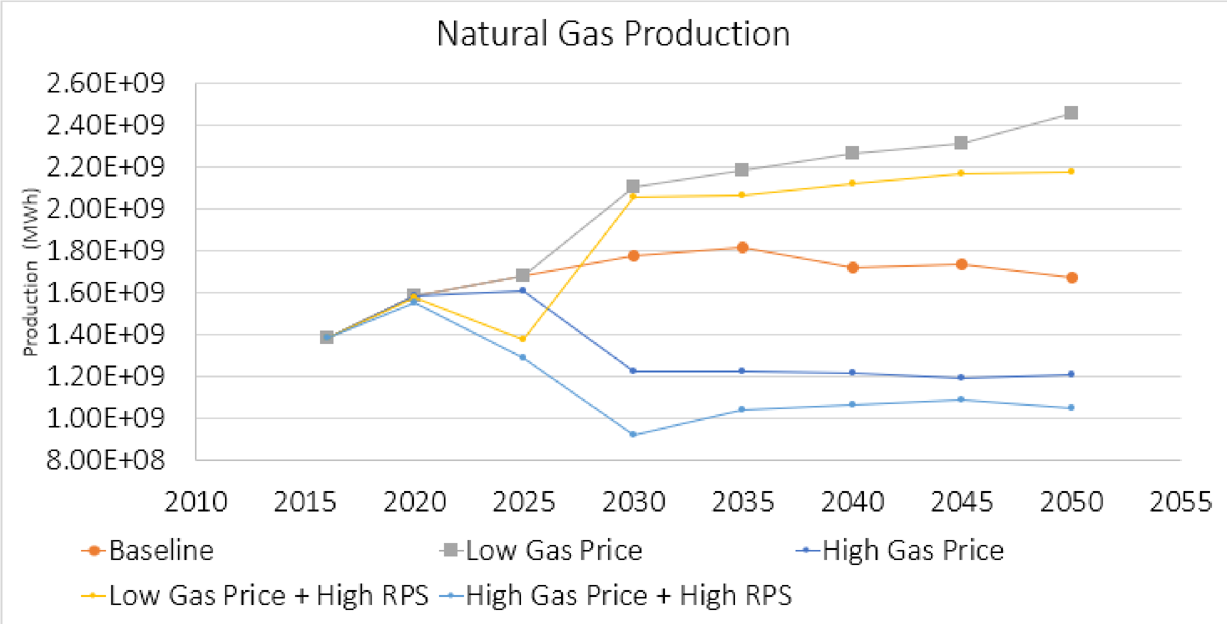


Figure D.7: Natural Gas Production Under Shock Scenarios

E Changes in Locational Marginal Prices in the US

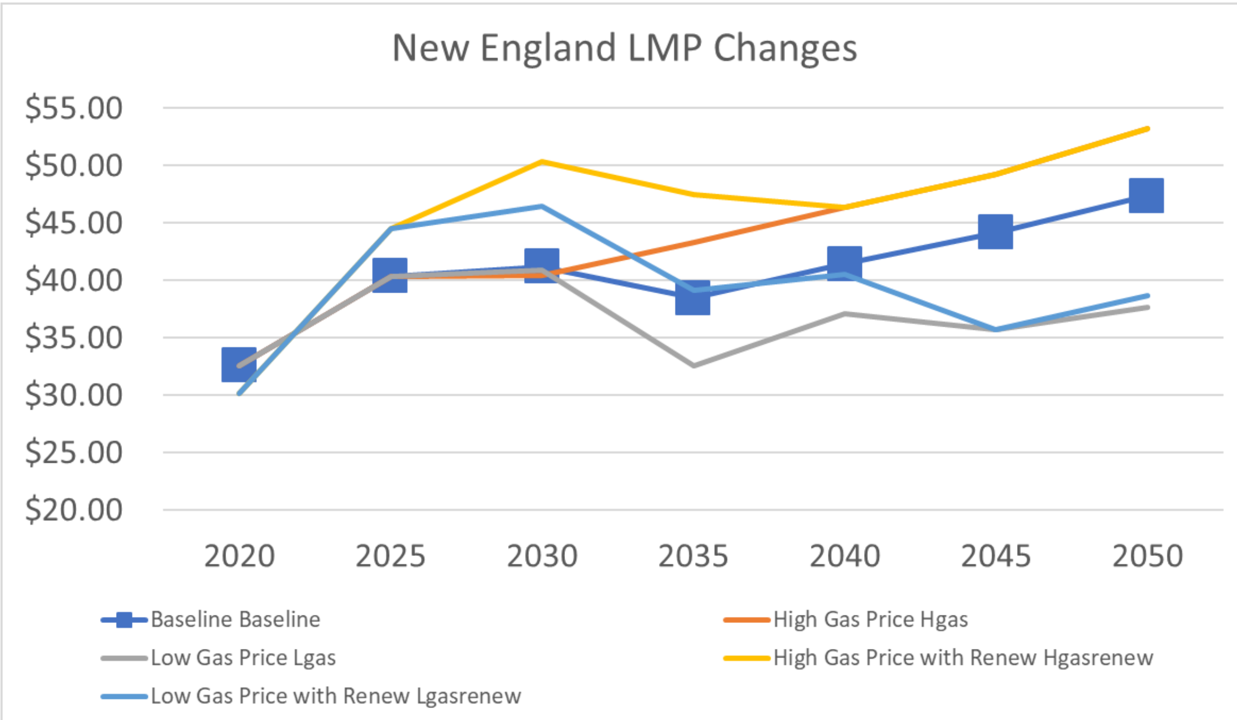


Figure E.8: New England Locational Marginal Prices

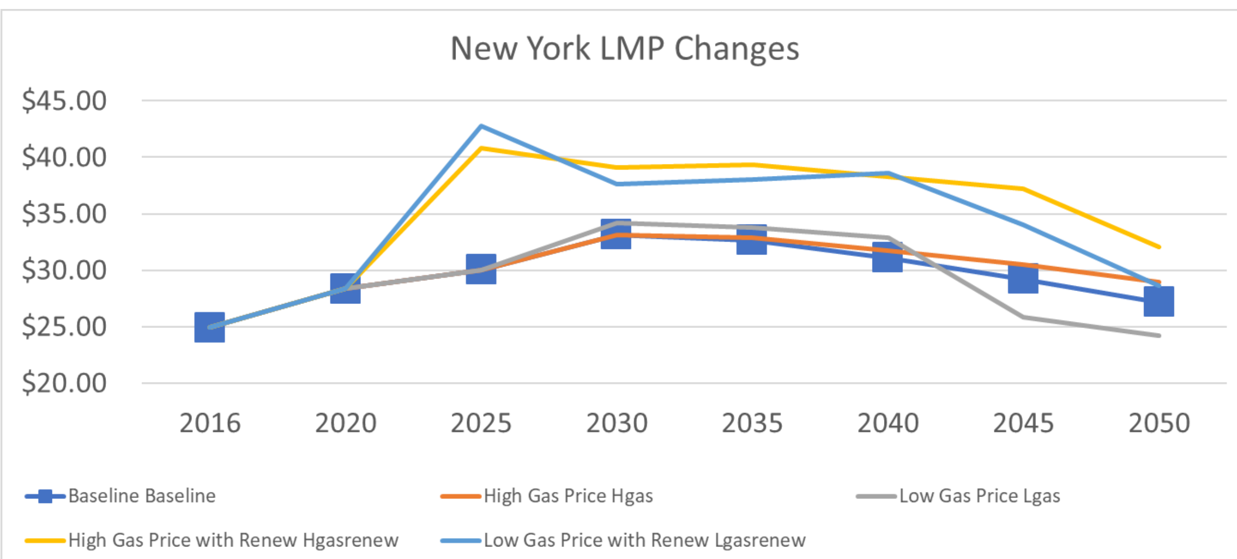


Figure E.9: New York Locational Marginal Prices

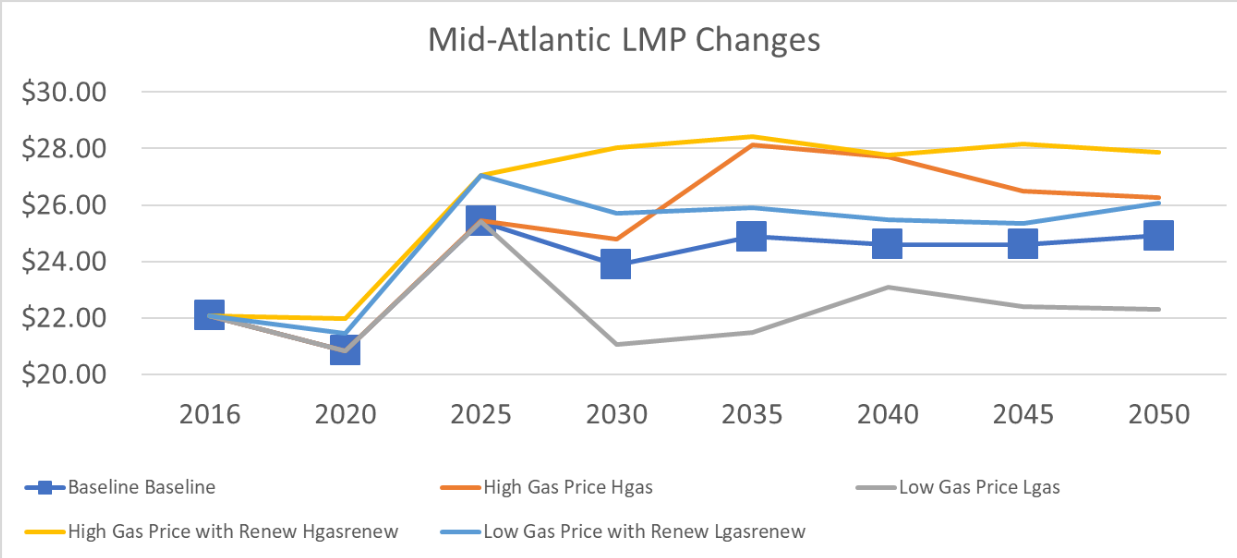


Figure E.10: Mid-Atlantic Locational Marginal Prices

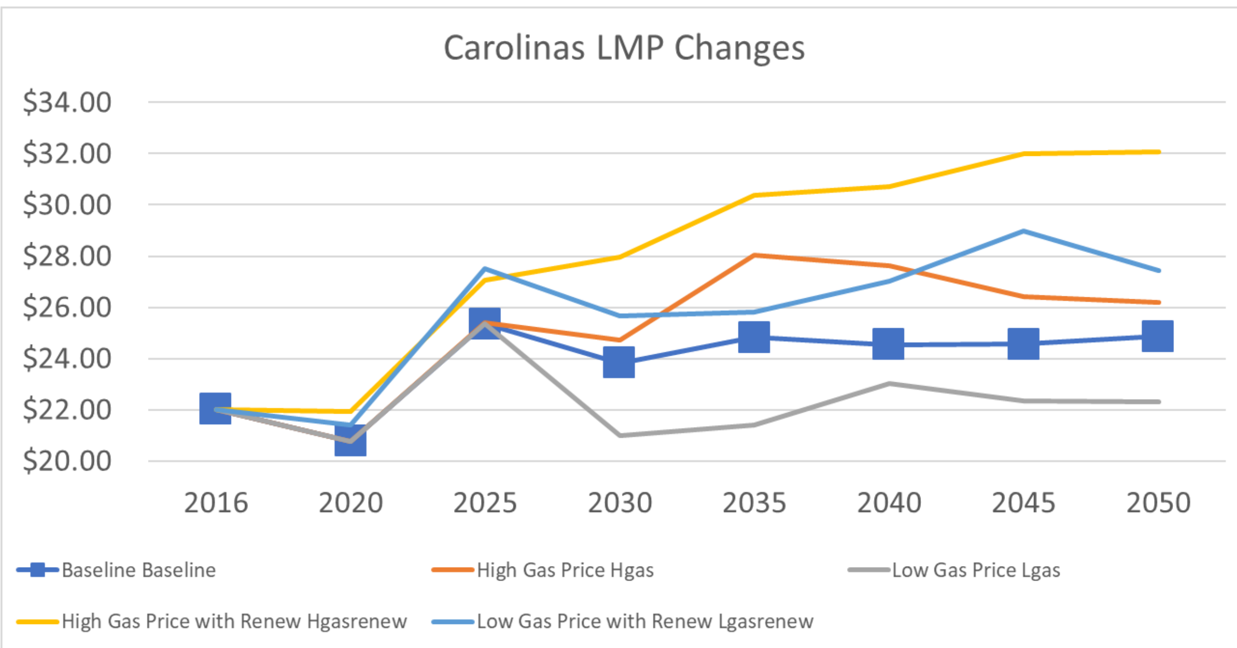


Figure E.11: Carolinas Locational Marginal Prices

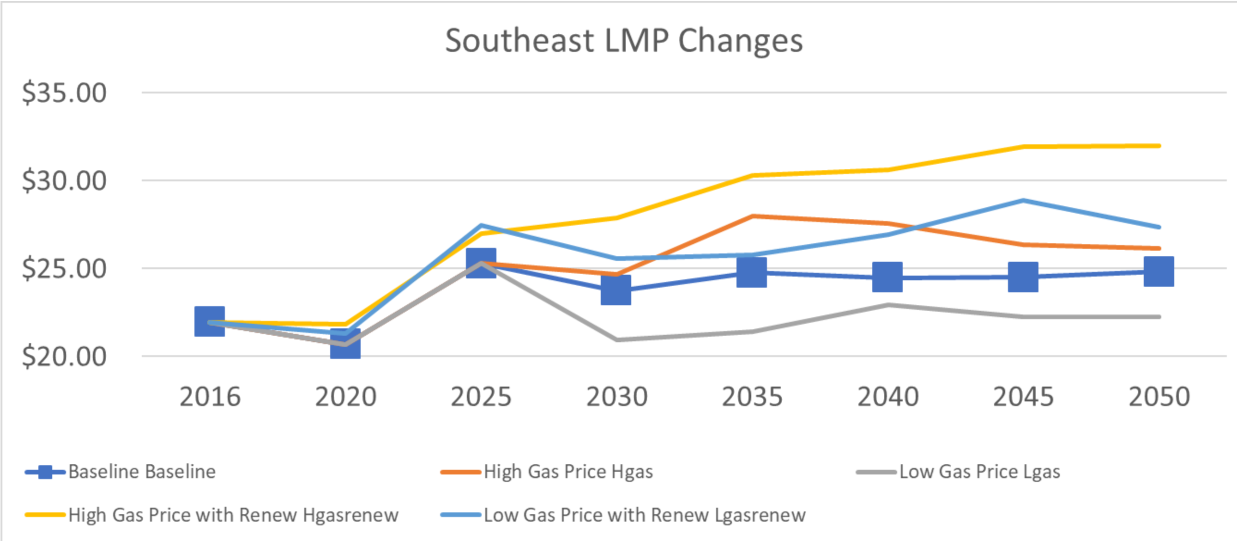


Figure E.12: Southeast Locational Marginal Prices

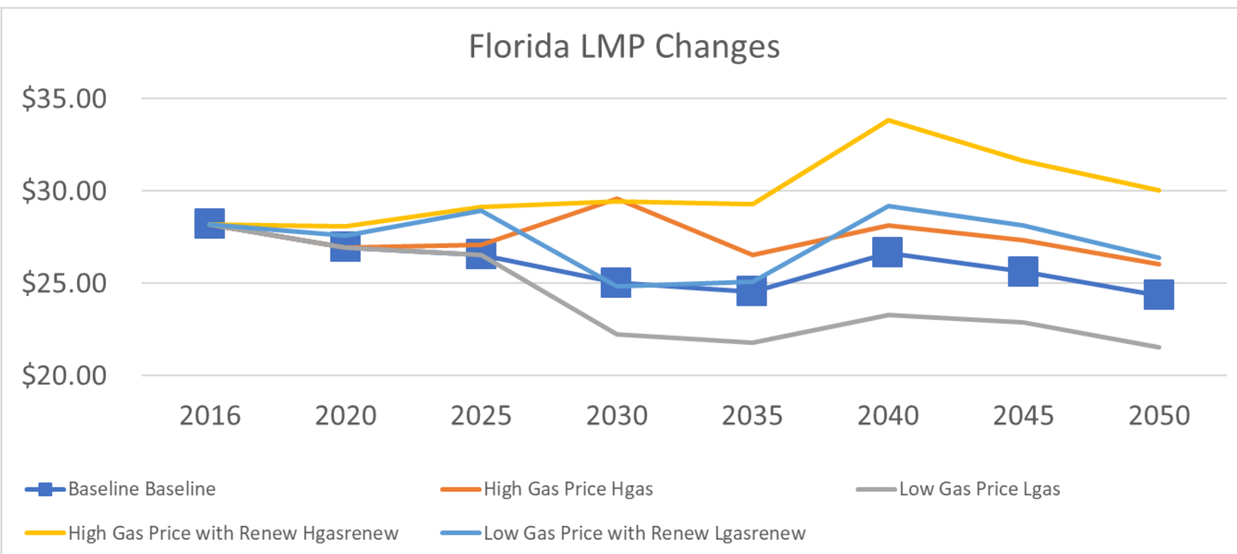


Figure E.13: Florida Locational Marginal Prices

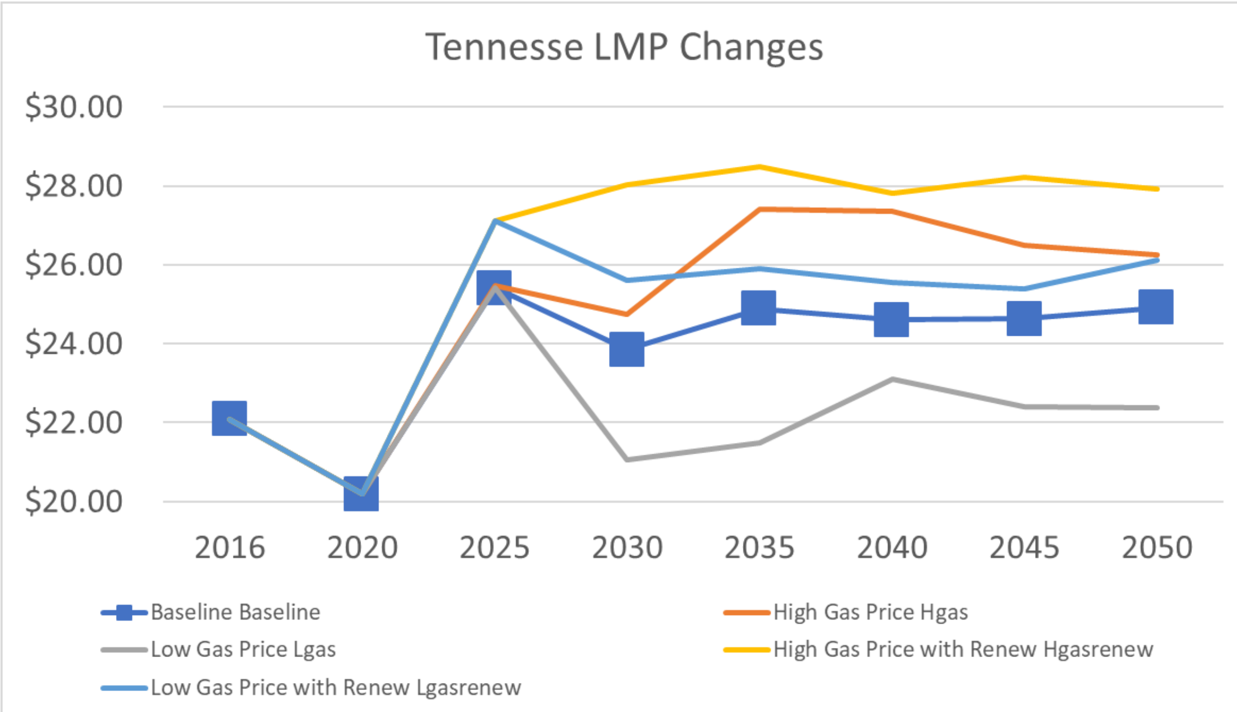


Figure E.14: Tennessee Locational Marginal Prices

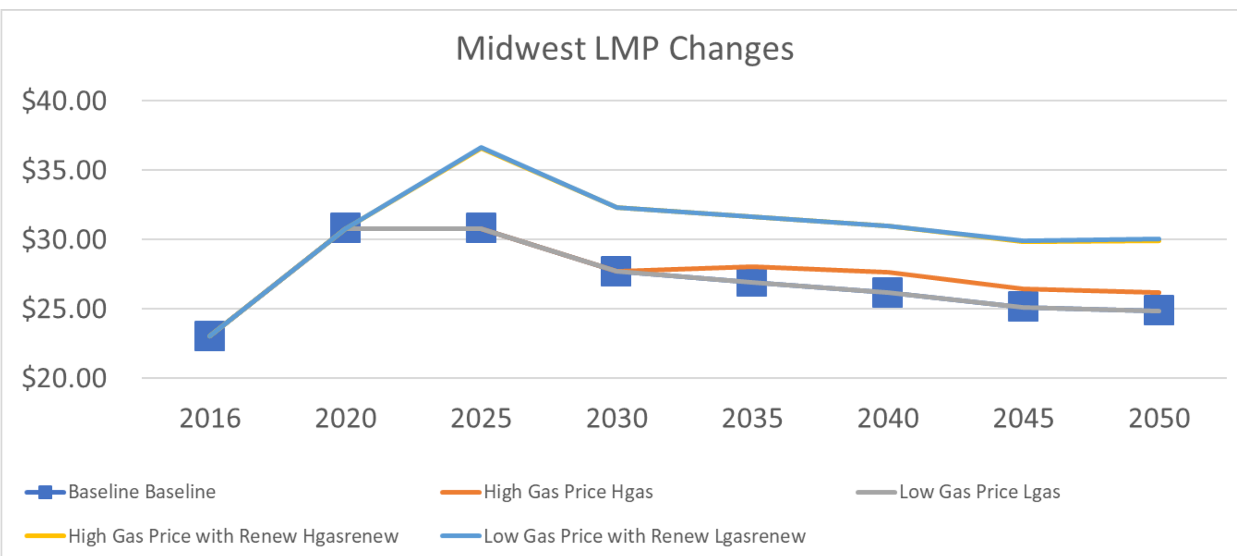


Figure E.15: Midwest Locational Marginal Prices

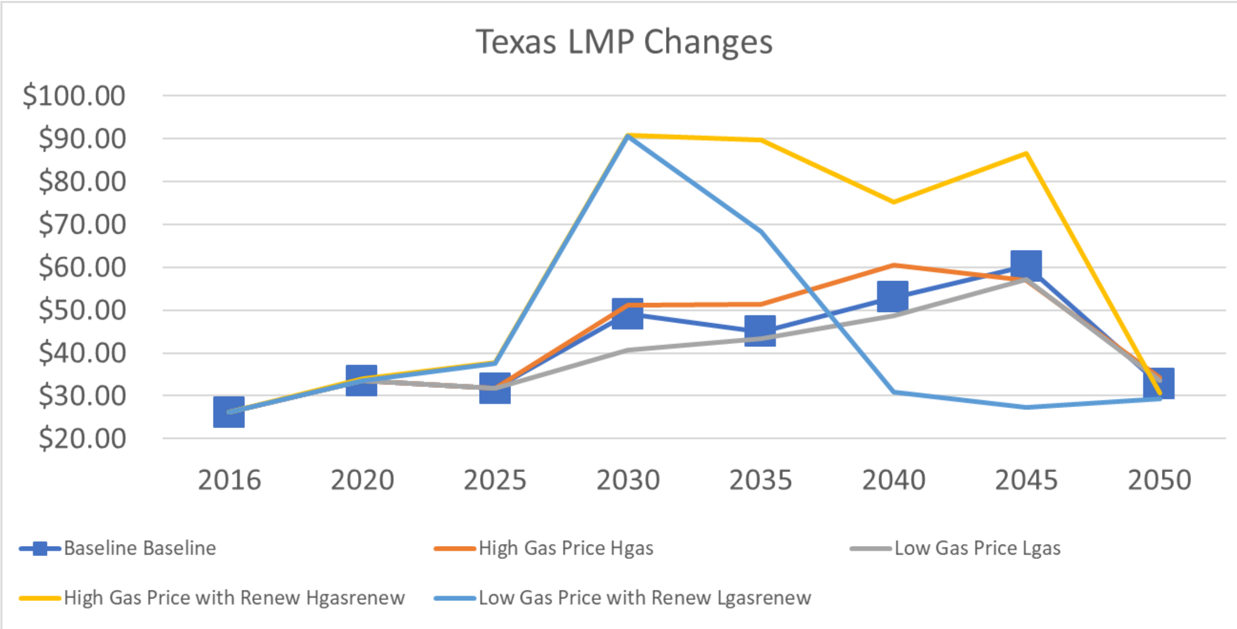


Figure E.16: Texas Locational Marginal Prices

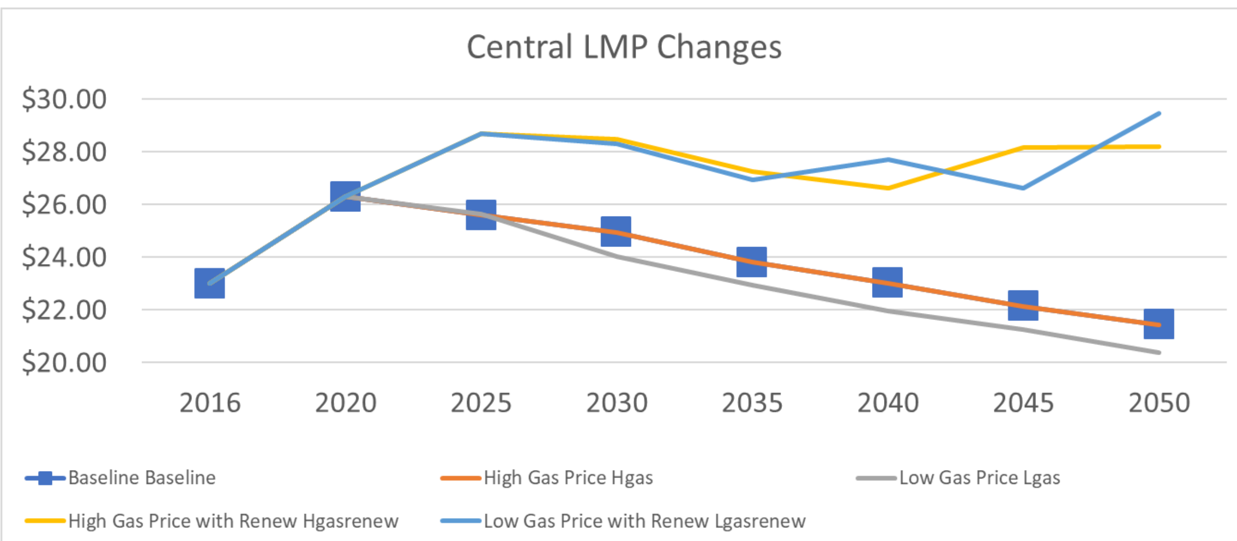


Figure E.17: Central Locational Marginal Prices

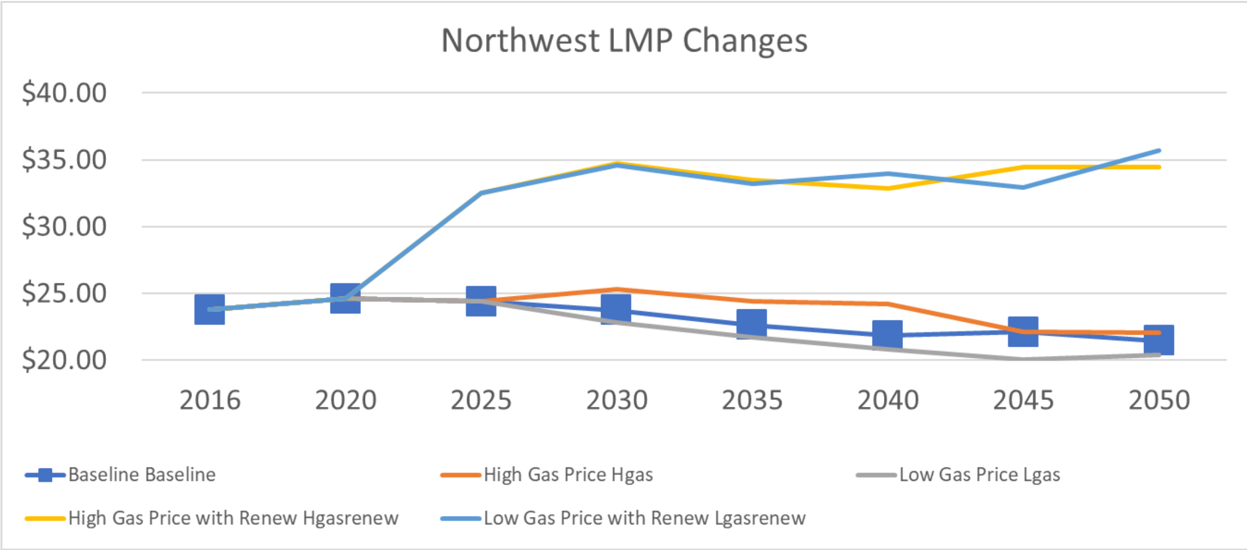


Figure E.18: Northwest Locational Marginal Prices

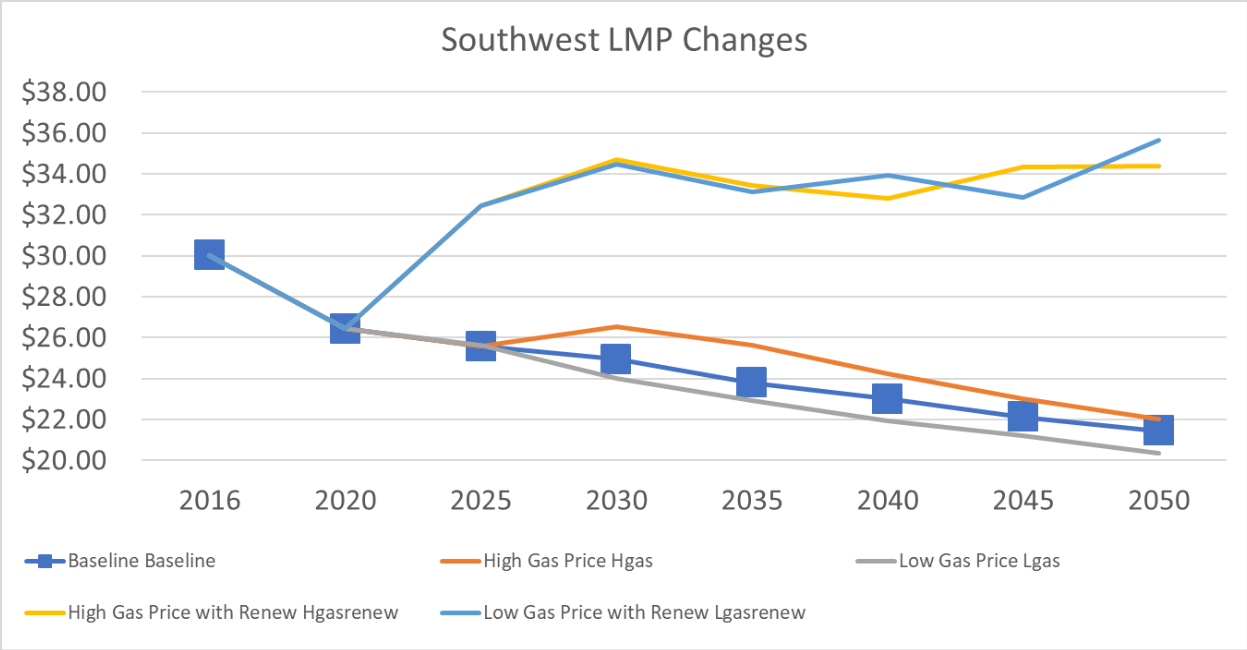


Figure E.19: Southwest Locational Marginal Prices

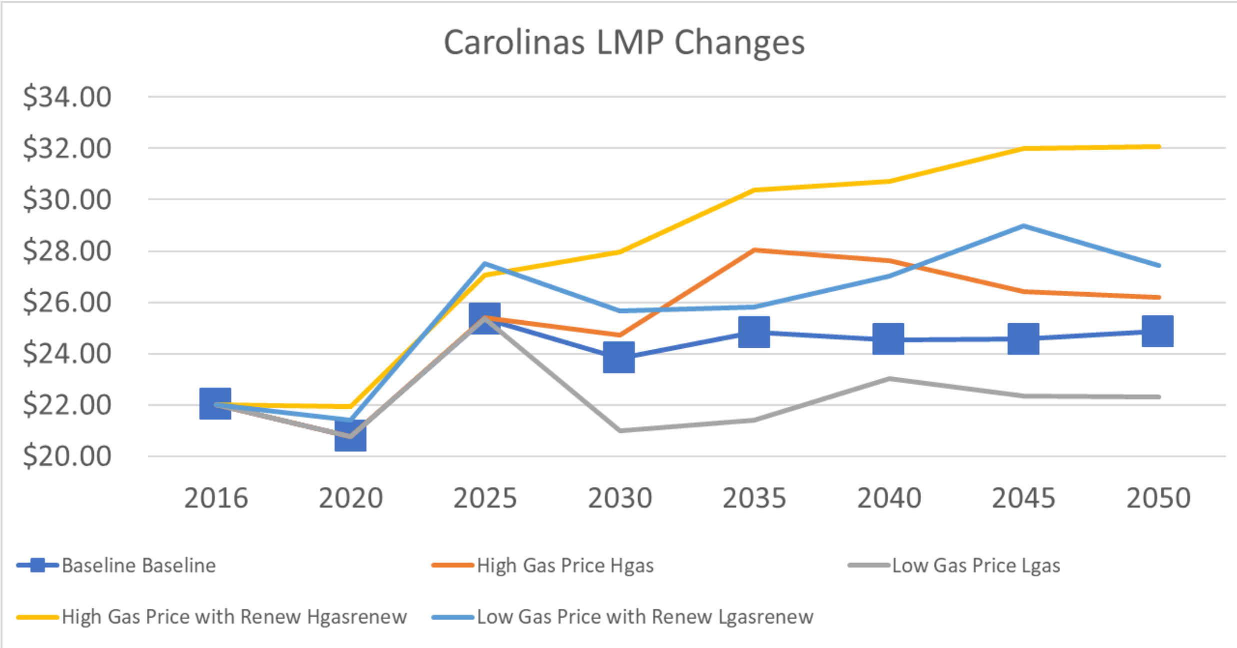


Figure E.20: California Locational Marginal Prices

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Curriculum Vitae

Adrian Ho-Sum Au (31st January, 1995) received his B.S. in Mechanical Engineering from the Johns Hopkins University. He returned to get his M.S.E. also in the Mechanical Engineering department with the focus on energy and the environment. Throughout his career at homes, he has gained an interest in all aspects of the energy industry.