A View to the Future of Natural Gas and Electricity: An Integrated Modeling Approach

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Abstract

This paper demonstrates the value of integrating two highly spatially resolved models: the Rice World Gas Trade Model (RWGTM) of the natural gas sector and the Regional Energy Deployment System (ReEDS) model of the U.S. electricity sector. The RWGTM passes electricity sector natural gas prices to the ReEDS model while the ReEDS model returns electricity sector natural gas demand to the RWGTM. The two models successfully converge to a solution under reference scenario conditions. We present electricity sector and natural gas sector evolution using the integrated models for this reference scenario. This paper demonstrates that the integrated models produced similar national-level results as when running in a stand-alone form, but that regional and state-level results can vary considerably. As we highlight, these regional differences have potentially significant implications for electric sector planners especially in the wake of substantive policy changes for the sector (e.g., the Clean Power Plan).

Keywords: Natural gas markets, electricity markets, market integration, capacity expansion modeling

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1. Introduction

In perhaps the most transformative development in energy markets in recent history, the United States is increasingly relying on natural gas extracted from shale formations (Logan et al. 2012). The scale of the shale gas resource carries broad economic, geopolitical, and national security benefits (Medlock, Jaffe, and Hartley 2011; Medlock, Jaffe, and O’Sullivan 2014). In April 2015 for the first time ever, natural gas exceeded coal as the largest source of power generation across the country (EIA 2015b), because its abundant supply has reduced its price while coal faces increased regulation.⁴ Indeed, natural gas has been pointed to as a bridge to a low carbon future (Brown, Krupnick, and Walls 2009; Kerr 2010), due at least in part to the increase of shale gas.

The impacts extend beyond U.S. borders as well, with the prospect of U.S. LNG exports having potential implications for global energy markets. This has also fueled debate on Capitol Hill regarding exports of domestically produced natural gas, with some claiming that LNG exports will drive up prices and diminish the benefits to domestic interests (see, e.g., Henderson (2012) for related discussion). Nevertheless, LNG exports from the U.S. may commence by the beginning of 2016, driven by the realities of international commodity trade (Medlock 2012). The new supplies that U.S. shale represent in the global marketplace also carry implications for natural gas pricing, as the growth in liquidity that will occur with market deepening stands to transform the nature of global LNG trade (P. R. Hartley 2014).

Finally, and most germane to this work, shale gas production has already tangibly lowered the domestic price of natural gas. In fact, from 2003-2006 the U.S. price of natural gas was among the highest in the world, yet now it is among the lowest. Among the potential benefits is that low domestic prices decrease the cost of compliance with several environmental regulations in the power generation sector. This, coupled with the recent economic downturn, has contributed to a significant reduction in U.S. CO₂ emissions.⁵

Natural gas appears to be a promising avenue for compliance with new environmental regulations, such as the Clean Power Plan (EPA 2015). However, it is important to understand how such policies might impact the price of natural gas, and hence its demand. In turn, this can convey an understanding of how the price of electricity may evolve over the next few decades given the relative abundance of natural gas against a backdrop of continual improvement in renewable energy technologies. In this paper, we utilize the Rice World Gas Trade Model (RWGTM) and the Regional Energy Deployment System (ReEDS) model in an integrated manner to understand how the electricity generation mix in the U.S. may evolve over the coming years. The use of these two models allows a very detailed view of the natural gas market to be married with a similarly detailed representation of the U.S. electric power market. In particular, we are able to capture the implications of regional natural gas price changes in the power

⁴ While not the focus of this paper, there is controversy surrounding various elements of the natural gas extraction process. For example, hydraulic fracturing, water use and disposal, land use, and increased traffic associated with shale development activity is calling into question whether the benefits outweigh the costs. Local environmental issues and community concerns about the rapid scale-up of shale-directed activity are impacting policy debates and have resulted in several local bans (see Medlock and Hartley (2015) for more on these issues).

⁵ Lower prices for natural gas also raise the prospect that natural gas could provide a commercially attractive alternative transportation fuel, which could provide tangible energy security benefits. In addition, low-price natural gas has revitalized the industrial base in the United States.

generation sector through time, then carry the feedbacks from power generation choices to upstream and midstream developments and LNG exports. The upstream, midstream, and LNG deployment can then in turn impact the natural gas prices that are observed by the power generators. Notably, LNG export volumes are endogenously determined by both international market conditions and domestic market conditions, so the ultimate choice in power generation in the U.S. is influenced by the international market. By iterating across modeling platforms we are able to produce a robust forward view of U.S. natural gas and electricity markets.

Recent regional planning efforts indicate that investments in new electricity generating capacity will be dominated by natural gas and renewables. For example, a recent survey of the utility resource plans in the Western U.S. found that 89% of the new capacity through 2030 would be natural gas, wind, solar, or hydropower (Wilkerson, Larsen, and Barbose 2014). As another example, Figure 1 shows data from the U.S. Energy Information Administration (EIA) that indicates proposed new capacity for 2014-2018 is largely natural gas and renewable energy generation. The projected growth of natural gas generation raises the question of infrastructure adequacy for both electricity and natural gas (AEE Institute 2015; DOE 2015a). The integrated modeling approach presented here determines the investments in pipeline and transmission capacity that are needed to balance demand and supply in the natural gas and electricity markets, respectively.

Figure 1: Proposed new capacity for the U.S. electricity sector (EIA 2015a).

A number of studies have been published considering the potential for natural gas abundance to reduce CO₂ emissions from the power sector (McJeon et al. 2014; Shearer et al. 2014; Shawhan et al. 2015). Although these studies tend to show that long-term CO₂ emissions are not generally reduced by abundant natural gas resources, several studies do indicate that natural gas abundance leads to substantial changes in the generation mix, ReEDS modeling included (Logan et al. 2013; Sullivan et al. 2015). Because of the large influence of natural gas supply on power system evolution, utilities consider future natural gas prices to be a critical uncertainty when making future resource plans (Wilkerson, Larsen, and Barbose 2014). A better understanding of the drivers of uncertainty can lead to more effective power system planning, and help to identify circumstances where natural gas and renewables can be complements (Cochran et al. 2014).

Geographic specificity is important in these considerations. Regulations such as the recent Clean Power Plan include state-level compliance targets (EPA 2015), and some resource plans include only the utility's service area with little detail on generators outside of the focus region (see Mai et al. 2015 for examples). It is not uncommon to find models with high spatial resolution for a single sector, but multi-sector models often accommodate their additional complexity by reducing their spatial resolution. This work brings together two sector-specific models that both have high spatial resolution. Our initial thesis was that representing both sectors with high spatial resolution will lead to more robust capacity expansion results, and the differences when compared to models with either less spatial detail or only one sector may be especially informative for region-specific policy and planning questions.

This paper illustrates the value of high resolution modeling of both the electricity and natural gas sectors through the integration of the RWGTM and the ReEDS model. A brief overview of the models used in this analysis, along with the process used in integration, is presented in Section 2. Section 3 presents the results of the analysis, and we close in Section 4 with some concluding remarks.

2. Methodology

Advances in computational methods and computing power have given modeling a central role in analysis and planning of energy systems. Model development is a regular part of the forecasting, strategic analysis and decision-making processes in many organizations, and the role of market models has developed to inform both corporate planning and government policy analysis. This research brings together a model of the global natural gas market (RWGTM) and a model of the North American electricity market (ReEDS), each of which have been successfully used in these regards for more than a decade. The RWGTM generates very specific outputs on natural gas supply, pricing, and infrastructure developments. The ReEDS model was developed with a special emphasis on renewable energy systems in the electricity sector. By bringing these two models together, we create an integrated modeling system that explores the technologies that are projected to meet growing electricity demands in the coming years.

In what follows, we offer summary detail of the RWGTM and ReEDS models. Each has been extensively used in a number of peer-reviewed studies, and greater detail is available therein, or upon request.

2a. The Rice World Gas Trade Model (RWGTM)

The RWGTM is a dynamic spatial partial equilibrium model of the global natural gas market.⁶ It is highly detailed, with over 290 global demand regions and 140 supply basins connected by an extensive representation of pipeline and LNG transportation options. There are 106 natural gas demand regions for the U.S. power sector. Natural gas prices are generated at 252 U.S. market hubs, some of which are commonly quoted liquid pricing points, while others represent major

⁶ The RWGTM was developed by Kenneth B. Medlock III and Peter R. Hartley at Rice University using the MarketBuilder software platform provided through a research license with Deloitte MarketPoint LLC. The architecture of the RWGTM, the data inputs, and modeled political dimensions are distinct to Rice and its researchers. A brief description of supply in the RWGTM is presented, but more detail is available upon request.

pipeline interconnects or offtake points within pipeline zones. The RWGTM solves every year from 2010-2040, every other year from 2040-2050, and every five years from 2050-2070.

The RWGTM is generally used to consider possible paths for natural gas investments, production, consumption, and prices – both regional and global – incorporating various assumptions on geology and well performance, economic outlooks, geopolitical influences, and various investment and trade barriers/incentives. This allows a robust assessment of the interactive effects of changes in these variables – political, economic and technological – on natural gas market development.⁷ The RWGTM is also used to understand the effects of changes in core economic variables affecting energy production – such as fiscal terms, limits on access to resources, fixed and operating costs, constraints on rigs, equipment and personnel, and technology.

Production of natural gas in the RWGTM requires investment in the development of resources, so finding and development (F&D) costs of resources are an important input. Even if technically recoverable resources are assessed to be very large, the relevant quantity is the commercially viable subset of what is technically recoverable. Technically recoverable resources define the resources that can be recovered with existing technology regardless of cost, whereas economically recoverable resources define what is commercially accessible. Resources that are “proved” are a subset of what is commercially viable, because proved reserves typically refer to resources that can be produced in a relatively short period of time. In sum, large resource in-place estimates do not imply large-scale production will be forthcoming. Productivity improvements, cost reductions, and price are all important in defining what is *technically recoverable* and what is *economically recoverable* relative to the *total resource endowment*.

As indicated above, F&D costs for natural gas resources are critical inputs. For non-shale resources in North America, F&D costs are based on estimates developed by the National Petroleum Council (NPC) in its 2003 report and have been adjusted using data from their 1998-2000 point of reference, using the Bureau of Labor Statistics (BLS) index on well development cost to account for changes through time. The F&D cost curves are developed by linking data on well development costs to the geologic characteristics of each play in areas where such information is known. The NPC report in 2003 aimed at assessing the future of the North American natural gas market and detailed costs for over 900 plays in North America. That data were utilized to develop an econometric relationship between costs and play level reservoir characteristics in non-shale resources, which was then used to generate costs (via an “out of sample” fit) in regions around the world where geologic characteristics are known, but costs are not. Much greater detail on the process is available in Hartley and Medlock (2006).

The RWGTM also contains detailed estimates of resource quantities and development costs for shale resources around the world. The initial assessments of technically recoverable shale resources are taken from the report “Technically Recoverable Shale Oil and Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States” by Advanced Resources International for the U.S. Energy Information Administration (EIA 2013). In developing F&D curves for shale, we also used data from the report “Review of Emerging

⁷ It should be noted that economic and political influences are not necessarily mutually exclusive, since policy can initiate changes in economic parameters.

Resources: U.S. Shale Gas and Shale Oil Plays” by INTEK, Inc. for the EIA (EIA 2011), as well as shale gas well production data across regions in the U.S. collected from DrillingInfo.com. The relevant geophysical data and well performance data are used to generate finding and development cost curves for an average shale gas well in every assessed basin. Then, the distribution of estimated ultimate recoveries (EUR) is econometrically fit to data for each shale play,⁸ which then allows us to sample at any point along the fitted distribution to obtain an EUR for a particular “tier” of well performance (see Figure 2).

Figure 2: Estimating EURs for Known Shale Plays (Barnett Shale indicated).

Characterizing shale gas production decline curves is a very important matter when modeling potential production, particularly give the relative importance of shale in the North American gas market. The models of physical flow through porous media that are the basis for the classically accepted Arps’ equations do not fit observed production data for shale gas wells. Patzek, Male, and Marder (2014) developed an alternative descriptor of decline curves for shale based on the physics of fluid flow in ultra-low permeability, ultra-low porosity rock media, such as shale. Their analysis resulted in a hypothesis that shale gas wells should decline so that production is inversely proportional to the square root of time. Medlock and Seithheko⁹ subsequently tested this hypothesis by linearizing their postulated decline curve and econometrically fitting it to a panel of over 16,000 wells in the Barnett shale. They could not reject the hypothesis of Patzek, Male, and Marder at a very high level of significance. This, in turn, allows for the construction of “type” curves, and facilitates a characterization of the distribution of well performances.

The cost per unit at each EUR is then determined as the ratio of the F&D cost in the play and the fitted EUR. Specifically, we determine the average per unit cost for each 20th percentile by: (1) assuming wells can be drilled uniformly in available acreage across the areal extent of the shale, (2) sampling from the EUR distribution and determining the total resource in each percentile of the distribution, then (3) taking a volume weighted average of the per unit costs at each

⁸ The regressions for the other shales in the U.S. also fit the data very well, with R^2 ranging between 0.9101 and 0.9963.

⁹ Medlock, Kenneth B and Likeleli Seithheko (2015), “Econometric analysis of shale gas decline curves in the Barnett” in review.

percentile in the distribution. Similar steps were taken for every shale play in the U.S. The steps taken and results obtained are extensively detailed in Medlock and Hartley (2015). Then, the parameters describing the distribution of shale gas well performance for plays in the U.S. are used to derive EUR distributions for shales around the world. This allows us to “tier” the resources according to cost for every shale in the world. Figure 3 indicates the breakeven curves, inclusive of fiscal terms and return to capital, for shale in North America.¹⁰

Figure 3: Shale Breakeven Curves for North America by Country.

Importantly, the resources can be tiered in a much more granular way by sampling at finer intervals on the EUR distribution. This in turn allows an assessment of the intensity of resource, capital and labor input in the production process. Moreover, the measure is specific to a shale play and producing region. This, in turn, can contribute to an assessment of the commercial viability of a potential producing area, which is critical for any assessment of the potential load resource development may place on the local environment. In other words, if the wells in a region are not highly productive, then their commercial viability may be compromised, which would reduce the incentive for drilling to occur. It is important to recognize that many factors influence cost and productivity, which leads to tremendous heterogeneity both across shales and within a shale. For example, shale that is clay-rich is generally not prone to high production rates, which in turn tends to reduce its commercial attractiveness even if the technically recoverable resource assessment is large. Other factors – such as total organic carbon, natural fracturation, isopach, permeability, porosity, and other features – are also critical. Altogether, this increases the degree of complexity in developing cost curves for undeveloped shale resources and imbeds a significant degree of uncertainty.

On the demand-side, in the U.S. demand is modeled for the commercial, residential, industrial and power generation sectors. In each sector, demand is price elastic, but elasticities are not

¹⁰ Similar curves are also available for the rest of the world. Importantly, one should not interpret the graphs in Figure 3 as classical long run supply curves. Rather, they are only illustrative of cost because the resources are geographically dispersed. Aggregating them ignores transportation costs to a generally accepted pricing location, and these transportation costs are heterogeneous across resources.

equal across sectors. This allows each sector to be price responsive under changing market conditions. The power generation sector in the RWGTM for this research is not modeled as price responsive. Rather, as will be explained below, natural gas demand for power generation is taken from the ReEDS model in an iterative process that involves the ReEDS model taking natural gas prices from the RWGTM. Significant detail regarding the steps taken to forecast natural gas demand in the RWGTM is available in Medlock and Hartley (2015), but now we turn to the ReEDS model.

2b. Regional Energy Deployment System (ReEDS) Model

The Regional Energy Deployment System (ReEDS)¹¹ capacity expansion model (Short et al. 2011; Sullivan et al. 2015) is an optimization model that can assess the deployment and operation (including transmission) of the electricity sector of the contiguous United States from 2010 through 2050 (solving even years only). It has high spatial resolution, capturing renewable energy resources through the use of 356 resource regions and modeling the electricity sector using 134 balancing areas (see Figure 4). ReEDS typically adopts natural gas prices as exogenous and taken from the Energy Information Administration's Annual Energy Outlook, with the prices resolved at the census region level. These prices are adjusted within the model using census-level supply curves. The census-level supply curves use the same general methodology as the national supply curves described by Logan et al. (2013). The supply curve methodology is described in the appendix. In this work, we consider both a scenario that uses these supply curves with AEO 2014 inputs and a scenario that ignores the supply curves and instead uses the RWGTM for all natural gas pricing inputs.

¹¹ The ReEDS model version 2015.1 was used for this work. This version of the model and associated inputs are described in detail by Sullivan et al. (2015).

Figure 4: ReEDS map showing the ReEDS regional structure.

ReEDS has been developed with an emphasis on characteristics important to renewable electricity technologies including variability, uncertainty, geographic resource specificity, and transmission. The high spatial resolution and statistical treatment of the impact of variable wind and solar resources enable a representation of the relative value of geographically and temporally heterogeneous renewable power resources. While the emphasis is on renewable technologies, ReEDS includes a full suite of conventional generating technologies, a system dispatch that includes seasonal and diurnal load shapes, a reduced transmission network, and dynamic capabilities for fuel supplies and electricity load. The major conventional thermal generating technologies in ReEDS include simple and combined cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. In addition to conventional generators, ReEDS models geothermal, hydropower, biopower, wind, and solar energy resources. Electricity storage technologies in ReEDS include pumped-hydropower storage, compressed-air energy storage (CAES), sodium sulfur batteries, and concentrating solar power with thermal energy storage.

2c. Model Integration

The RWGTM has high spatial representation of the natural gas sector including detailed resource supply curves, but has a limited representation of the electricity sector. ReEDS is a detailed electricity sector model with limited representation of the natural gas sector. Therefore, integrating the two models allows the detailed representation in one model to inform inputs to the other in an iterative fashion.

The initial step in integrating the models involved mapping the 252 RWGTM U.S. natural gas price hubs and 104 demand regions to the 134 ReEDS balancing areas. This was performed manually by comparing region-level maps. This proved to be a complex exercise as the RWGTM is developed with a very detailed mapping of the U.S. pipeline grid as demand sinks are sited along the network to simulate flows with historical accuracy, while ReEDS is developed with distinct attention given to siting of renewable generation technologies and how they might compete in the existing electricity market. As a result, the siting of natural gas demands for power generation did not always map well across the models. Where there was more than one option for mapping, existing natural gas power plants and their ties to market hubs or regional demand centers were used to determine which region was a better choice for the mapping. After the initial mapping was completed, a single iteration between the two models was performed. Results from this iteration were used to verify that the mapping did not introduce any significant *near term* distortions to either model.¹²

Figure 5 depicts a schematic that summarizes the integration of the two models. RWGTM generates natural gas hub prices through time, which are imported into ReEDS. ReEDS then determines the electricity sector capacity expansion for the U.S. and generates spatially disaggregated natural gas demands from the electricity sector. This demand is then loaded into the RWGTM. The process repeats until natural gas prices and electric sector natural gas demands cease to change, indicating convergence across the models, where convergence was defined as a less than 1% change in annual natural gas demand between iterations.

Figure 5: Integration of RWGTM and ReEDS.

An important and subtle conversion is required before inputting the RWGTM outputs for natural gas hub prices, or wholesale market prices, into ReEDS. Specifically, ReEDS requires natural gas electricity sector prices at the point of sale. Electricity sector natural gas prices are generally higher than hub prices because the electricity sector prices include the cost of the transaction and delivery of the gas. To convert the hub price from RWGTM (p_{RWGTM}) to an electricity sector price for ReEDS (p_{ReEDS}), a price markup (p_{markup}) was included, such that

¹² For this purpose, we focus on the near term because it maps well to historically observed load flows in both markets.

$$P_{ReEDS,i} = P_{RWGTM,i} + P_{markup,i} \quad (1)$$

where the index i denotes the 134 ReEDS balancing areas. In this way each balancing area has a unique p_{markup} and unique electricity sector price.

The p_{markup} values for each ReEDS balancing area were determined by constraining the model to match historical natural gas demands for each of the 134 ReEDS balancing areas. The resulting shadow prices, $\mu_{i,t}$ (where the index t denotes the historical year), on the demand constraint represents the price required to balance each ReEDS region above the wholesale price of natural gas from the RWGTM. Accordingly, we then obtain a p_{markup} for each balancing area such that

$$p_{markup,i} = \min(\mu_{i,t}). \quad (2)$$

Finally, we then constrained $p_{markup,i}$ to exist on the interval between the minimum and maximum observed differences between the state-level electricity-sector prices reported by EIA (2014a), p_{EIA} , and the RWGTM hub prices for 2010-2013, such that

$$\min(p_{EIA,i} - p_{RWGTM,i}) \leq p_{markup,i} \leq \max(p_{EIA,i} - p_{RWGTM,i}). \quad (3)$$

Because EIA electricity prices are reported at the state level, p_{EIA} was the same for all i within a state. The p_{markup} values for the 134 regions range from \$0.29/MMBtu to \$1.65/MMBtu, with an average value of \$0.55/MMBtu (all in 2014\$). Figure 6 shows the ReEDS natural gas demand in 2014 versus the historical natural gas demand. The R^2 between the ReEDS natural gas demand and historical natural gas demand in 2014 is 0.96.

Figure 6: Comparison of ReEDS natural gas demand to historical natural gas demand across each ReEDS balancing area (BA) in 2014.

2d. Model Scenarios

Two scenarios are presented in this work. The first scenario is the converged ReEDS-RWGTM scenario which uses the RWGTM natural gas prices. The second scenario is a standalone ReEDS scenario that uses AEO 2014 electricity sector natural gas prices (EIA 2014a) resolved at the EIA census region level. These prices are modified within ReEDS based on the actual ReEDS demand using a previously published supply curve methodology (see Logan et al. 2013) in which natural gas prices respond positively to demand.¹³ The distinct difference across the two scenarios is that the former, noted as the ReEDS-RWGTM case, leverages a detailed representation of resource costs curves and pipeline transportation costs whereas the latter scenario, denoted as the ReEDS-AEO2014 case, does not approach the interaction between the electric sector and the natural gas sector in as highly a disaggregated manner.

With the exception of the natural gas prices, all other ReEDS inputs are identical in the two scenarios. ReEDS technology cost and performance inputs for these scenarios are the same as those used in the Wind Vision Report (DOE 2015b) and draft version of the 2015 Standard Scenarios Annual Report (Sullivan et al. 2015). The electricity production growth across the two scenarios is set at the same rate as in the RWGTM status quo scenario. As a point of reference, electricity production growth in the U.S. from 1986 through 2005 was 2.25%. However, since 2005 electricity production growth has been tempered by a weak U.S. economy as electricity production growth has slipped well below one percent per annum. In the RWGTM status quo scenario, it is assumed demand growth re-emerges, although not to the same rates witnessed prior to 2005. In fact, electricity intensity (defined as electricity production per unit GDP) continues to decline, falling by about 35% from 2015 through 2050. Given real GDP growth is assumed to be 2.7% per year through 2050, we have an average electricity production growth rate from 2015 through 2050 of about 1.9% per year. While various efficiency programs and/or

¹³ The ReEDS-RWGTM scenario does not adjust the RWGTM natural gas prices using the supply curve methodology in the ReEDS-AEO2014 case.

lower GDP growth rates would almost certainly result in demand-side responses, and in turn lower U.S. electricity production growth rates, we leave that to future scenario analysis.

3. Results and Discussion

The ReEDS-RWGTM scenario and ReEDS-AEO2014 scenarios produce similar electricity sector natural gas prices at the national level (see Figure 7). Both scenarios show a steady, but nearly linear, increase in natural gas prices over time. Because all ReEDS inputs are the same (except for the natural gas prices) for the two scenarios, the national level results are also quite similar. Figure 8 and Figure 9 show the capacity and generation, respectively for the ReEDS-RWGTM scenario. Demand growth driven by new load growth and retirements is met primarily by natural gas generators, wind turbines, and utility-scale and rooftop photovoltaics. Annual natural gas generation exceeds coal generation beginning in 2038 and remains the dominant generation technology through the remaining time horizon. Nuclear capacity goes nearly to zero by 2050 because in these scenarios ReEDS does not allow nuclear plants to be granted a second relicensing. Nuclear relicensing would impact the capacity and generation mix post 2030, but nuclear retirement sensitivities are beyond the scope of this paper.

Figure 7: National weighted-average electricity sector natural gas prices for ReEDS using RWGTM natural gas prices (ReEDS-RWGTM) and for ReEDS using AEO 2014 natural gas prices (ReEDS-AEO2014).

Figure 8: Installed capacity by technology type in the ReEDS-RWGTM scenario. Gas-CT is gas-fired combustion turbine and Gas-CC is gas-fired combined cycle.

Figure 9: Generation by technology type in the ReEDS-RWGTM scenario. Gas-CT is gas-fired combustion turbine and Gas-CC is gas-fired combined cycle.

Although national level results are generally consistent between the two scenarios, regional and state-level results can vary considerably. Figure 10 and Figure 11 highlight the electricity sector natural gas prices for the 134 ReEDS balancing areas in 2030 across the ReEDS-RWGTM and ReEDS-AEO2014 scenarios, respectively. The AEO 2014 prices are much more uniform due to the aggregate nature (EIA census regions) at which the prices are reported and hence applied in ReEDS. However, the RWGTM prices are tied to specific market hubs, so there is significantly greater variation in prices for the ReEDS-RWGTM cases.

Figure 10: Electricity sector natural gas prices in ReEDS in 2030 in the ReEDS-RWGTM scenario for the 134 ReEDS balancing areas.

Figure 11: Electricity sector natural gas prices in ReEDS in 2030 in the ReEDS-AEO2014 scenario for the 134 ReEDS balancing areas.

The differences in balancing area prices lead to different dispatch and investment decisions at the regional level across the two cases. Figure 12 shows the median state-level differences among three outputs between the ReEDS-RWGTM and ReEDS-AEO2014 scenarios for 2030. Natural gas generation varies the most strongly between scenarios, followed by CO₂ emissions, and renewable energy generation. These differences due to a more granular representation of natural gas prices indicate that smaller regional studies, such as those that might be done to assess state-level policy or investment decisions, may benefit from region-specific information rather than general or national level projections.

Figure 12: Median relative difference between ReEDS-RWGTM and ReEDS-AEO2014 state-level outputs in 2030. The absolute value of the differences was used in generating these values so that positive and negative differences would not cancel out.

Figure 13 and Figure 14 demonstrate how the more granular representation impacts state-level CO₂ emission in 2030. The national-level CO₂ emissions vary by less than 1% between the two scenarios, but state-level differences can be considerably different. In general, states with lower absolute emissions tend to exhibit greater relative changes (e.g., Vermont shows a -94% difference between scenarios, but an absolute difference of -0.02 million metric tons). This scenario comparison demonstrates that differences in state-level natural gas pricing data can lead to similar national conclusions, but substantially different state-level conclusions.

Figure 13: Difference in state-level CO₂ emission in 2030 between the ReEDS-RWGTM and ReEDS-AEO2014 scenarios. Values are ReEDS-RWGTM minus ReEDS-AEO2014 such that positive values indicate higher state-level emissions in the ReEDS-RWGTM scenario.

Figure 14: Relative difference in state-level CO₂ emission in 2030 between the ReEDS-RWGTM and ReEDS-AEO2014 scenarios. Positive values indicate higher state-level emissions in the ReEDS-RWGTM scenario.

4. Concluding Remarks

In this work we have integrated the Rice World Gas Trade Model (RWGTM) and the Regional Energy Deployment System (ReEDS) model to demonstrate the importance of regional detail in evaluating future renewable energy sources and natural gas interactions in the U.S. power generation sector, and how the differences in generation mix can lead to different state-level CO₂ emissions. The RWGTM passes natural gas prices to the ReEDS model, which in turns solves the capacity expansion and dispatch problem for the electricity sector and returns the electricity sector natural gas demand to the RWGTM. Both models have high spatial resolution, thus allowing an examination of the impacts of highly spatially resolved natural gas prices on the outputs of electricity sector modeling.

We have found that compared to the EIA AEO 2014 natural gas price representation using nine census regions, the linked RWGTM-ReEDS model produces similar aggregate national-level results. However, regional and state-level results vary substantially with the higher granularity representation. New environmental rules, such as the Environmental Protection Agency's Clean Power Plan, will require regional or state-level planning for regulatory compliance. This paper highlights that it will be important for various stakeholders to consider regionally distinct representations of natural gas and electricity markets in order to make highly informed decisions. Indeed, results can be quite different when comparing the highly disaggregated regional or state-level model outputs to electric sector projections that only consider national-level or census-level natural gas price forecasts.

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7. Appendix

The Regional Energy Deployment System (ReEDS) is a long-term capacity expansion model of the United States power sector. The ReEDS model by itself does not explicitly model the U.S. natural gas (NG) system, which system touches all sectors of the economy and includes complex infrastructure and markets. Rather, a supply curve representation is used to approximate the NG system.

The premise of using regional supply curves is that the price in each region will be a function of both the regional NG demand and the national NG demand. Regional NG supply curves were derived from AEO 2014 (EIA 2014a) for each of the nine EIA census regions (see Figure 15). We extracted the regional and national NG consumption and price for the electricity sector for the 31 AEO 2014 scenarios. We then subtracted the regional combined heat and power NG consumption from the total NG consumption data to obtain electricity-only NG consumption (ReEDS only represents electricity-only generators).

Figure 15: The nine census regions defined by EIA (EIA 2014a). A regional supply curve was created in ReEDS for each of these census regions.

We used the AEO 2014 scenarios to estimate parameters for the following NG price-consumption model:

$$P_{i,j} = \alpha + \alpha_i + \alpha_j + \alpha_{i,j} + \beta_{nat} Q_{nat,j} + \beta_i Q_{i,j} \quad (4)$$

where $P_{i,j}$ is the price of natural gas (in \$/MMBtu) in region i and year j , the α parameters are the intercept terms of the supply curves with adjustments made based on region (α_i), year (α_j), and the region-year interaction ($\alpha_{i,j}$), β_{nat} is the coefficient for the national NG demand (Q_{nat} , in quads), β_i is the coefficient for the regional NG demand ($Q_{i,j}$) in region i . Note that the α parameters in (4) can be represented using only $\alpha_{i,j}$. Nine of the 31 AEO 2014 scenarios were

removed as outlier scenarios. These outlier scenarios typically included cases of very low or very high natural gas resource availability, which are useful for estimating NG price as a function of supply, but not for estimating NG price as a function of demand—for given supply scenarios.

The national and regional β terms are reported in Figure 16. We made a specific post-hoc adjustment to the regression model’s outputs for one region: the β_i term for the West North Central (WNC) region was originally an order of magnitude higher than the other β_i values because the WNC usage in the electricity sector is so low (0.05 quad¹⁴ in 2013, compared to ~0.5 quad or more in most regions). The overall natural gas usage (i.e., not just electricity sector usage) in WNC is similar to the usage in East North Central (ENC), so intuitively it makes sense to have a β_i for WNC relatively close to that of ENC. We therefore manually adjusted the WNC β_i term to be 0.6 (in 2004\$/MMBtu/quad), and recalculated the alpha terms with the new beta to achieve the AEO 2014 target prices. The situation in WNC of such a small fraction of NG demand going to electricity is unique; we do not believe that the other regions warrant similar treatment.

Figure 16: β values for the nine census regions. The “National” value at the far left is β_{nat} . A β of 0.2 means that if demand increases by one quad, the price will increase by \$0.20/MMBtu (see equation (4)).

Comparison to Literature Values

Technical literature tends to report the price elasticity of supply and the price elasticity of demand, which are estimates of the supply and demand, respectively, of a good given a change in price. In the formulation given by equation (4), we attempt to estimate a value that is similar to the price elasticity of demand—we estimate a change in price given a change in demand. Therefore we present here a comparison against the price elasticity of demand as the closest available proxy, noting however that it is not necessarily identical to estimates of β . Price elasticity of demand is typically negative, but will be reported here as a positive number for convenience.

¹⁴ A quad is a quadrillion Btu, or 10^{15} Btu.

External sources are varied and often vague in their estimates of price sensitivity of natural gas. Using the reported domestic NG market demand given for 2012 in AEO 2014, the β values reported in this work yield an overall NG sector elasticity value of 0.36-0.92 (higher values of β correspond to lower elasticity values). Arora (2014) estimated the price elasticity of demand for NG to be 0.11-0.70, depending on the granularity and time horizon of the NG price data considered. Bernstein and Griffin (2006) examined the price elasticity of demand for residential NG usage, and estimated the long-run elasticity to be 0.12-0.63 depending on the region. The Energy Modeling Forum at Stanford University reports NG price elasticity of demand for 13 different energy models (Huntington 2013). The reported elasticity ranges from 0-2.2 depending on the year, model, and scenario considered. For the National Energy Modeling System (NEMS) used for the Annual Energy Outlooks, the elasticity ranges from 0.22-0.81 depending on the year and scenario (Huntington 2013).

The EPA's proposed Clean Power Plan includes a projection that natural gas usage will increase by 1.2 quads in 2020, resulting in an 8-12% increase in NG prices for the electric sector (Smith 2014). This corresponds to a β_{nat} of 0.38-0.51 in 2004\$/MMBtu/quad.