Does a Detailed Model of the Electricity Grid Matter? Estimating the Impacts of the Regional Greenhouse Gas Initiative

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Abstract

The consequences of environmental and energy policies in the U.S. can be severely constrained by physical limits of the electric power grid. Flows do not follow the shortest path but are distributed over *all lines* in accordance with the laws of physics, so grid operators must select which generation units to operate at any moment, not only to minimize production costs, but also to prevent the system from collapsing because of line overloads. Because of the complexity of power grid operation, combined with current or past computing limitations, the previously existing power sector policy simulation models use highly simplified representations of network flows. Using an economic/engineering model of the power grid developed and calibrated for the eastern US and Canada, we explore the effect of such simplification on the accuracy of simulation results. To evaluate the amount of detail necessary, we simulate the short- and long-term effects of imposing a price on the carbon dioxide emissions from the power plants in nine northeastern US states, as the Regional Greenhouse Gas Initiative does. We consider three grid models that simplify the actual 62,000-node system to varying degrees. Our 5,000-node model matches the 62,000-node model closely. We use it as the basis for evaluating the more simplified models: a 300-node model and a model with just one node, i.e. no transmission constraints. With each of the three models, we predict the CO_2 emission impacts, electricity price impacts, and generator entry and exit impacts of the emission price, over the next 20 years. We find that most of the impact predictions produced by the 300- and one-node models differ from those of the 5,000-node model by more than 20%, and some by much more. Fortunately, recent advances in computational ability make use of large network models feasible.

1. Introduction

Electric power generation is responsible for large shares of the emissions of several high-profile pollutants. In the US, for example, power generation accounts for approximately 40% of carbon dioxide (CO_2) emissions (USEPA, 2012), 55% of mercury emissions (USEPA, 2013a), and 60% of sulfur dioxide emissions (USEPA, 2013b).

The effects of policies to reduce these emissions depend on the particular characteristics of the power sector. The constraints and flow patterns in an electric power grid can greatly influence the ability of generators favored by a policy to substitute for other generators, and therefore can greatly influence the results of the policy. Models of the grid's operation are therefore necessary to predict the effects of a policy, or of a new transmission line or generator. However, a grid has many lines, nodes, and constraints. For example, the Eastern Interconnection has tens of thousands of each. Furthermore, more than a hundred thousand flow equations can be necessary to describe how power will flow on those lines. The flows in power networks do not just follow the shortest or most under-utilized route from where power is generated to where it is consumed; instead they move along *all* connected lines, including lines that may already be dangerously overloaded, in accordance with Kirchoff's Law of physics.[1] A line operating beyond its safe "thermal limit" will heat up, sag, and likely discharge to a tree or other grounded object, potentially causing a cascading blackout like the northeast US and Canada blackout of 2003. System operators strive to avoid this. The main means of avoiding the overloading of a line is to employ optimal power flow software that shifts to using generators

[1] Specifically, Kirchoff's Voltage Law.

located such that they alleviate the flow on that line. Consequently, in reality, location matters, even among nodes that may be aggregated together into one aggregate node of some model. Furthermore, for the reasons just mentioned, one line at its limit may affect the pattern of generation, emissions, prices, profits, generator entry, and generator retirement over a small area or a large area. A model that does not represent individual lines may not be able to predict well what will be the effects, even the aggregate effects, of the constraints on those individual lines.

When power system models are used for benefit-cost analysis, they need to be able to project long-term effects, which means they need to calculate optimal entry and retirement of generators, taking into account the variations in demand that occur during different hour types that occur over a year. The resulting problem of maximizing net benefits subject to electric grid constraints is so enormous that policy analysis models have been forced to aggregate the many real nodes into a much smaller number of nodes. Because of current or past computational limitations, and in some cases because of a desire to include other useful but computationally costly features, models typically employed for analysis of environmental polices use only dozens of nodes. The ICF IPM Model (USEPA, 2011), the US Department of Energy NEMS model (USEIA, 2009) , the Resources for the Future Haiku model (Paul et al, 2009), MARKAL (USEPA, 2013c), and the National Renewable Energy Laboratory ReEDS model (NREL, 2011) are several such models for the US.

This paper examines whether network detail in a power sector simulation model matters, and therefore whether models with less transmission system detail produce less reliable results. It also provides some indication of *how much* detail is necessary. We compare the predictions of three models of the Eastern Interconnection that are identical except that they use transmission-system representations with three different degrees of simplification. One model uses 5,000

nodes, another uses 300, and the other uses one node (no transmission constraints at all). The Eastern Interconnection covers the US and Canada east of the Rocky Mountains except for Quebec, northern Canada, and most of Texas and includes approximately 74% of US and Canadian peak electricity demand (NERC 2012). The complete network model that we obtained for the Eastern Interconnection (Energy Visuals, 2012) contains 62,000 nodes.

Network reduction techniques from electrical engineering were used to create the three simplified representations. Each simplified representation combines clusters of the original 62,000 nodes into larger, aggregate nodes. The 5000-node model retains each high-voltage line (of 230 kiloVolts and above) as a separate line and so does not combine any two high-voltage nodes or high-voltage transmission lines. The reasons to preserve these lines separately are that their placement in the system makes them the carriers of most long-distance flow, and they are the lines most likely to impose constraints that significantly affect the operation of the grid. The behavior of the 5000-node model matches the behavior of the 62,000-node model very closely, as we substantiate in section 2. To assess the importance of transmission-system detail in simulations, we use the 5000-node model as a benchmark against which to compare the results of the 300-node and one-node models. It is well documented in the economics literature that aggregation introduces error (for a summary of this literature see Stoker, 2008). We measure how much compared to the 5,000-node model.

This paper makes two contributions to the environmental and energy economics literature. The first is to demonstrate the use of a detailed network model in an economic model for predicting the effects of a policy. Very similar methods and tools could also be used to predict the effects of a potential new transmission line or generator. The second contribution is to test the effects of network model simplification on policy predictions.

We use Ward reduction for network simplification and a direct-current approximation for simulation, so we specifically test the effect of that type of network simplification in conjunction with that type of simulation. Of the policy analysis models mentioned above, only the ReEDs model uses similar methods. Nonetheless, our test is important for five reasons: First, it suggests that the ReEDS model would likely benefit from more transmission system detail. Second, our methods are already commonly used for purposes less computationally difficult than policy analysis. Third, they mimic the operation of real power systems, so they may replace simpler methods even in policy analysis, now that computational technology is finally making this feasible. Fourth, they can be used for new purposes such as predicting the long-term effects of potential new transmission lines and generators. Fifth, there is some similarity among policy simulation models, so or results may help other modelers decide whether to use the new computing improvements to try adding more transmission detail to their models.

In the process of pursuing the two modeling improvement contributions mentioned above, we project the effects of a regional emission price, specifically a $10 per ton price on carbon dioxide (CO_2) emissions under the Regional Greenhouse Gas Initiative (RGGI). In this paper, the RGGI allowance price is simply the sample policy on which we demonstrate and test the modeling techniques that are the focus of the paper. The allowance price is just one part of the RGGI policy package, and we do not attempt to model even the emission price precisely. A reader interested in careful evaluation of the RGGI policy package should see ICF Consulting (2006) and Analysis Group (2011) or some new analysis that may have emerged after this writing. Nonetheless, some description of the policy is in order. RGGI is a CO_2 cap-and-trade program that applies to the power plants in nine northeastern US states. The RGGI state governments are planning to tighten the total cap on emissions, and that could result in a $10

price per ton by 2020. The US EPA is preparing rules to require states to regulate CO_2 emissions from power plants. This is unlikely to end RGGI, in part because the rules may give the states multiple compliance options (Wald, 2013) and RGGI may be one (Miller, 2013).

The adjacent regions of the US and Canada trade power freely with the RGGI states but are not subject to the RGGI cap. Network constraints determine the amount of "leakage" that can occur to these neighboring non-RGGI regions, so the representation of the transmission system may be important in estimating the effects of the policy. Leakage refers to the increased emissions at generators outside of the regulated region as a result of policy-induced cost increases for generators covered by the regulation.

The paper is organized as follows: The electricity system and market model used in this analysis is described in Section 2, followed by a description of data development and sources in Section 3. The cases modeled and the results of simulations are summarized in Section 4. Conclusions and implications for future policy simulations are presented in Section 5. Readers who are not interested in the technical details can skip directly to Sections 4 and 5.

2. The Model

Our model projects the operation of the power system as well as generator entry and retirement. We iterate the model over three time periods, labeled year 0, year 10, and year 20. In year 0, the generators that existed on December 31, 2010 (the latest available data and very close to the current situation) are included. Year 0 represents the "short run" in the economic sense because in it we have constrained generator entry and retirement to be zero. In contrast,

years 10 and 20 are the economic long run in that the model predicts generator entry and retirement.[2]

The model, specified below, combines characteristics of a conventional analytical model with important physical details of the power grid. The specification is similar to that developed by economists specializing in electricity markets who have long recognized the importance of line constraints (e.g., Kirschen and Strbac 2004 pp. 186-191, Hogan 1992, Joskow and Tirole 2000, Schweppe et al 1988, Oren 1997, Crew and Kleindorfer 1979, and Bohn et al 1984). Improved computation technology has finally made it possible to use such a specification in conjunction with a detailed transmission system model and prediction of entry and retirement.

We use a direct current (DC) approximation of the actual alternating current (AC) electric grid because for planning purposes, past research has shown that a DC approximation is adequate (Shawhan et al., 2012), and it aids in computational tractability. This approximation is also used by system operators in their optimization of flows that maximizes net benefits, but they do not predict entry and retirement of generators.

The model includes nodal demand, generator output, and locational marginal prices. Costs of fuel, of operation, and of construction are exogenous, as is the demand function at each node. In each time period, the model endogenously determines usage and emissions of each generator, total cost, and change in producer plus consumer surplus relative to the base case. In addition, it endogenously determines the following at each node: price and quantity demanded in each representative hour, and generator investment and retirement (except in year 0). The model takes the following form:

[2] This model does not endogenously build or expand transmission lines. Doing so would add enormously to the size of an already large problem, and the prospect of gaining approval for new lines in most parts of the modeled region is daunting. Therefore, the simulations presented here take the existing network as given.

$$\max_{p_{ijk},\, I_{ij},\, R_{ij}} \left\{ \sum_i \sum_j \left[\begin{array}{c} \left(\sum_k H_k \left(B_{jk} - \left(c_i^F + a_{jk} e_i \right) p_{ijk} \right) \right) \\ -\left(c_i^T \left(p_{ij}^0 + I_{ij} - R_{ij} \right) + c_i^I I_{ij} \right) \end{array} \right] \right\}$$

subject to

$$p_{ij}^0 + I_{ij} - R_{ij} \geq p_{ijk}$$

$$p_{ijk} \geq \alpha_i^{\min} \left(p_{ij}^0 + I_{ij} - R_{ij} \right)$$

$$K_{ij} > I_{ij}$$

$$\sum_i p_{ijk} - L_{jk} + \sum_{j'} S_{jj'} (\Theta_{j'k} - \Theta_{jk}) \geq 0$$

$$F_{jj'} > \left| S_{jj'} (\Theta_{j'k} - \Theta_{jk}) \right|$$

where the following notation is used:

i: Generator index

j: Node index

k: Representative hour index

p_{ijk}: Aggregate real power output from generator i at node j during representative hour k. (Price-responsive demand is modeled as negative generation.)

p^0_{ij}: Capacity of generator type i at node j already existing at the beginning of the year

R_{ij}: Capacity of generator type i retired at node j during the year

I_{ij}: Capacity of generator type i at node j newly built during the year

c^F_i: Variable cost per MWh of generator i, including cost of fuel and variable operations and maintenance costs

c^T_i: Annual fixed costs per MW, including taxes, insurance, and fixed operating and maintenance costs

c^I_i: Levelized per-year cost per MW of new investment in generator type i if its total investment cost is amortized over ten years

H_k: Hours per year represented by representative hour k

e_i: Carbon dioxide emission rate for generator i, tons/MWh

a_{jk}: Carbon dioxide emission price at node j in hour k, \$/ton

α_i^{min}: Minimum generation fraction of capacity for type i

K_{ij}: Maximum feasible investment in fuel type i at node j

B_{jk}: Piecewise linear consumer surplus function associated with non-fixed portion of demand.

L_{jk}: Quantity demanded (also called "load") at node j in representative hour k

$F_{jj'}$ Flow limit from node j to node j'

$-S_{jj'}$ Susceptance of the line from node j to node j'

Θ_{jk} Phase angle of node j. (The difference in phase angles between two nodes drives flow)

The model maximizes annual gross consumer surplus minus the sum of variable operating, fixed operating, and annualized investment costs. The control variables are the output of each generator in each hour, the quantity demanded at each node, the construction of new generators, and the retirement of existing generators. The constraints, in the order shown, require the following:

- Generation cannot exceed the pre-existing capacity plus the amount of new generation capacity minus the amount of newly retired capacity.
- Each generator that is on must produce at least its minimum output. In the study reported in this paper, that minimum output is zero for all units except coal generators to allow generators to effectively be turned off during some or all representative hours of the year. Coal units cannot be operated below 15% of their maximum generation during the year.
- Total new entry by a particular generator type can be no greater than the specified limit on feasible construction in the decade.
- Generation minus quantity demanded at each node equals the net flow across all line segments that touch that node. The shadow price on this constraint determines the nodal price of electricity.
- The electricity flow on each line cannot exceed the line's flow limit. This is where the lines' transmission limits come into play.

In the scenario with RGGI, the variable cost of each emitting generator includes an emission price per megawatt-hour that is the product of its emission rate and the assumed emission price of $10 per ton.

The criterion for retirement implicit in the optimization is that the generator's annual revenue if it remained in service would be less than the sum of its annual variable operating and fixed operating costs. Note that existing generators do not have to cover investment costs in order to continue to exist. The criterion for entry is that the revenues in the first ten years of the generator's existence must exceed or equal the variable and fixed operating costs in those ten years plus the unit's total investment cost. This calculation assumes that the revenues and costs in those ten years will be the same as in the representative year in which the generator first exists. Investment cost includes an 8% annual cost of capital on any portion of first cost not yet recovered.

Developing a simplified or "reduced" representation of the 62,013-node eastern US-Canadian grid was a major part of the modeling effort and required the development of some new techniques, described in detail in a related engineering paper (Shi, et al., 2012). We use a common method known as Ward reduction (Brown 1985) in which some lines ("branches" in the parlance of engineers) are retained (i.e. not aggregated), the nodes on those lines are retained, each other node is aggregated into the most closely connected retained node, and the other lines are represented by "equivalent" lines that connect some pairs of the retained nodes. A Ward reduction has the advantage that it remains an electrical model. A user can simulate its operation using the laws of physics, including Kirchoff's Voltage Law. Hence, it is an aggregation method suited to electrical networks.

The standard Ward-type reduction method splits each generator across multiple nodes. However, this does not make sense for economic modeling. Since the network constraints require that power flowing into a node must equal power flowing out of a node, each node has a constraint with a unique multiplier or "locational marginal price" derived from the optimal power flow used to dispatch generators in real world systems and in models of those systems. This implies for economic modeling that split generator would face multiple prices. So we developed a means to keep each generator at a single node while still retaining the congestibility pattern of the original network (Shi et al 2012). We do this by moving small amounts of demand in a precisely specified fashion, to compensate for keeping each generator at just one node.

By design, a Ward reduction precisely and correctly predicts flows in retained lines for the particular nodal distribution of electricity generation and consumption upon which the reduction is based. The reactances (similar to resistances) of the equivalent lines are set to the unique set of values that produces this result. No significantly reduced network model of any kind can exactly replicate the behavior of the more detailed model on which it is based. An imperfection of our models is that the equivalent lines in our models do not have transmission constraints. This is because the effective flow limit between two retained nodes on the network of unretained lines varies according to factors such as the locations of generation and consumption. However, since power flows distribute themselves across all lines according to Kirchoff's Law, the constraints on the retained lines also limit the flows on equivalent lines, though not perfectly. Again, aggregation introduces error. Characterizing the extent of the error caused by greater aggregation, in a particular case, is a major purpose of this paper.

For our "5000-node" model, we reduced the original 62,013-node system to 5,222 by retaining all high-voltage (230 kV or above) lines as well as other lower-voltage lines that are

prone to congestion. All other lines were aggregated into equivalent lines between retained nodes. The resulting 5,222-node model has 14228 transmission lines, of which 6596 have flow constraints. Its behavior matches the behavior of the original 62,013-node system very closely. To compare them, we used each to calculate the cost-minimizing feasible combination of generator outputs for a sample hour. In a comparison between the two networks, the total cost differed by just 0.31% and the average locational marginal price of electricity differed by just 0.025%. Solution time between solving for the full 62,013 node representation and the reduced 5,222 node system dropped by a factor of 23 (Shi et al., 2012).

For our "300-node" model, we reduced the original 62,013-node model to 293 nodes by retaining the lines identified as congested in the US Department of Energy's National Electric Transmission Congestion Study (USDOE 2006, 2009) and the associated line terminals as nodes. All other lines were aggregated into equivalent lines between retained nodes. It has 1328 flow constraints, of which 216 have flow constraints. The "1-node" model is the 300-node representation with all transmission constraints removed between nodes.

3. Data

Developing and aligning the data to be consistent with existing facilities was a major component of this research effort. The model was calibrated with data for existing generators from the US Energy Information Administration for December 31, 2010 (EIA, 2012.) We matched many of these units with the summer 2011 list of generators provided by Energy Visuals, Inc, which were supplied by operators as part of the 2010 planning process of the Multiregional Modeling Working Group. The fuel type, maximum generation capacity, and geographic location for each unit is known from EIA data. For units that were matched with the

Energy Visuals list of units, we know estimated heat rate, estimated fuel cost, estimated variable operating and maintenance cost, and location on the electric grid. For units that we were not able to match to the Energy Visuals data, their location on the grid was determined by geographic location. For their heat rate, fuel cost and variable operating cost, we used the average of units of the same unit type and fuel type for which we had those values. For coal, natural gas, oil, and petroleum coke units, we calculated their CO_2 emissions using their heat rates and fuel type. The projected fuel costs for coal and oil units are constant, since EIA projections for coal costs vary by less than 2% over the next 30 years, and oil is a relatively minor power generation fuel. We assumed natural gas prices of $2.50, $4.77, and $5.86 per million British thermal units, respectively, for years 0, 10 and 20. The year-0 price reflects the actual natural gas price of our base year data. The prices for years 10 and 20 are EIA projections (USEIA, 2011).

We included six types of potential new power plants that the model might evaluate for future construction: dual-unit advanced pulverized coal plants, advanced natural gas combined-cycle plants, advanced natural gas combustion turbines, dual-unit nuclear plants, large-scale solar photovoltaic facilities, and onshore wind generation. Estimates of the capital and other annual fixed costs, both for new and existing units, as well as their heat rates and non-fuel variable costs were obtained from (USEIA, 2010b) and (USEIA, 2011b). In addition to the EIA's estimate of fixed operating and maintenance cost, we added taxes and insurance payments, as detailed in the appendix. We assumed that the current tax credits for new wind and solar units would be eliminated by the first year of our simulation. At the natural gas prices assumed, only advanced natural gas combined-cycle units and advanced natural gas combustion turbines were built because the four other types have higher total costs, regardless of capacity factor.

To estimate non-variable costs, we convert the overnight capital costs reported by the EIA into a total construction cost by assuming that an equal portion of the overnight cost is spent at the beginning of each year of the project's construction, and that the debt accrues interest at an annual rate of 8%. We assume that a power plant in a highly uncertain competitive environment will be built only if it is projected to pay back its investment in the first 10 years of operation. The capital recovery factor for ten years and an annual interest rate of 8% is 14.9%, whose development is detailed in the appendix. A complete table of estimated fuel prices, costs and capacity additions is also provided in the appendix.

In order to represent a generator's operation over an entire year, we construct twelve representative hours, four from each of three "seasons": summer (May-September), winter (December-February), and Spring+Fall (the other four months). For each season, we used data from Federal Energy Regulatory Commission Form 714, supplemented by data representing Canada. We ranked the 8760 real hours of 2010 by total electricity quantity demanded ("load") in the Eastern Interconnection and divided them into four bins. We classified the top 5% of hours as peak, the next 25% as high, the next 40% as medium, and the bottom 30% as low. We divide the model into its six NERC regions, as shown at http://www.ercot.com/content/news/mediakit/maps/NERC_Interconnections_color.jpg, and calculate the mean load in each region in each bin. We calculate a load multiplier for each each NERC region for each representative hour. Our transmission model contains load at each node for a summer peak hour, so the load multiplier is 1 for the summer peak representative hours. In each region, for the other eleven representative hours, it equals the proportion of mean load in that bin to mean load in the summer peak bin.

In addition, we scale the maximum power output of each generator by season to account for unplanned outages (in the summer) and a combination of unplanned and planned maintenance outages (the other seasons, especially the fall and spring). This scaling serves two purposes: first, no generator, no matter how economical, can expect to be available and receive payments 100% of the time, and second, sufficient excess generating capacity will be available on the system to represent the system operator's desire to have "adequate" generating capacity to meet demand at all times.

In order to reflect the long run response by customers to variations in electricity prices, a price elasticity adjustment was added to forecast underlying projections in demand growth caused by demographic and income factors. Recent surveys and studies of the long-run price elasticity of demand for electricity have shown a wide range of values. Jorgensen et al. (2012) provide a meta-analysis of econometric studies since 1951 and found a slight decrease in long-run elastictity from .76 before 1980 to .58 after 2000. But Patrick et al (2012) found a slight increase over time. The reliability of all of these studies has been questioned by Fell, Li and Paul (2012) who argue that customers respond not to electricity prices, but their monthly bill with an elasticity close to 1.0. Other researchers supporting this view include Shin (1985), Borenstein (2009) and Ito (2001). We use a middle value of .6 for this study.

There is a separate demand function at each node in each representative hour. The first 75% of quantity demanded will be demanded regardless of price. The last 25% consists of ten steps, each representing 2.5% of maximum quantity demanded. The tenth has a price equal to the price at that node in that representative hour in year 0 of the base case (i.e. no policy). The ninth has a price 4.167% higher. The eighth has a price 8.33% higher, and so on. So, for

example, if marginal cost of retail supply (wholesale price plus $70 per megawatt-hour) were 6% higher in the policy case than in the base case, quantity demanded would be 5% lower.

Total demand also grows from year 0 to year 10 and 20 as a result of increasing population, wealth and adoption of new electricity-using devices. We examined growth rates and changes in the average price of electricity from 1990 to 2010 in order to estimate load growth in each NERC region in the absence of changes in electricity prices. This load growth varies from a low of 8% per decade in the NPCC (Northeast) to 23.7% per decade in the FRCC (Florida.)

4. Cases Modeled and Results

To evaluate the effects of network detail in modeling the transmission system, we compare the predictions of three models of the Eastern Interconnection. They are identical except that they respectively use a 5000-node, 300-node, and single-node representation of the transmission grid, as described previously. We use these models to predict a set of outcomes in three time periods: the first year of the policy ("year 0"), the tenth year, and the twentieth year. Using each model, we predict outcomes both with and without a $10 per ton price on carbon dioxide emissions from power plants in the nine states that participate in RGGI. As previously described, the existing generator fleet is used for the initial period, but entry and generator retirement is permitted after that.

The main question of this paper is whether transmission system detail in transmission system simulation of policies matters. The results reported here show that it can indeed matter. In summary, the predictions of the 300-node model differ significantly from those of the 5,000-node model in some important ways. The predictions of the one-node model generally differ

even more, illustrating the general importance of using a model that takes into account transmission constraints. We will focus on comparing the predictions of the 5,000- and 300-node models, specifically their predictions regarding effects of a $10 RGGI emission price. We will highlight five outcomes for which the predictions of the two models differ substantially: Emission quantity within RGGI, emission "leakage" from RGGI, effect of RGGI allowance price on electricity price in RGGI, electricity prices, and effect of RGGI allowance price on year-20 emissions. The main cause of these differences in the predictions of the 5,000- and 300-node models is the smaller number of constraints in the 300-node model. For each difference, we will explain how.

Emission quantity within RGGI. If the designers of a cap and trade program wish to approximately target a particular emission allowance price, then they need to be able to predict the emissions at that price. Table A shows that in year 10, with a $10 RGGI allowance price, the 5,000-node model predicts within-RGGI emissions of 69 million tons per year, while the 300-node model predicts 58 million tons per year. If the more detailed model were precisely correct, then the prediction of the less detailed model would represent a 16% underprediction. The results in years 0 and 20 are similar. In general, absent some allowance price ceiling, this sort of prediction error could result in issuing too few permits, and consequently having an allowance price much higher than intended. Alternatively, if the target is instead a certain quantity of emissions, then a prediction error of this magnitude could result in setting a price ceiling too low or a price floor too high, such that the desired quantity cannot be achieved.

Table A: Carbon Dioxide Emissions Subject to the Regional Greenhouse Gas Initiative

	Model Used	Year 0	Year 10	Year 20
	1 Node	109,274,886	94,961,366	114,869,381
No Policy	300 Node	80,873,100	93,475,259	104,760,955
	5,000 Node	86,637,372	99,770,654	123,609,657

	1 Node	54,254,639	46,426,309	60,461,374
Policy*	300 Node	55,439,574	57,964,776	55,006,769
	5,000 Node	68,354,796	68,901,179	62,346,980
	1 Node	-55,020,247	-48,535,057	-54,408,007
Policy Effect	300 Node	-25,433,526	-35,510,483	-49,754,186
	5,000 Node	-18,282,576	-30,869,475	-61,262,677

*$10 permit required for each short ton of CO_2 emissions from a generator in the RGGI states

Emission leakage. Table B shows the predicted effect of the RGGI policy on emissions both inside and outside of the RGGI region. The effect on emissions outside the RGGI region is "leakage." Leakage can exceed the effect on emissions within the regulated region if the generation increase outside that region is sufficiently more emission-intensive than the generation decrease inside that region. This is the case in our simulation, because coal, with a CO2 emission rate approximately twice that of natural gas, is at and near the margin much more outside of the RGGI region than inside it. Both the 5,000-node and 300-node models predict that the RGGI allowance price will increase total emissions in years 0 and 10, and decrease total emissions in year 20. However, the magnitudes of the projected total emission impacts differ. The 5,000-node model always predicts a lower (less positive or more negative) effect of the $10 RGGI allowance on total Eastern Interconnection emissions. The largest difference is in 2032. The 5,000-node model predicts a total reduction of 18 million tons (15% of what the RGGI region's generators would emit without the policy), while the 300-node model predicts a total reduction of 6 million tons. Our model probably overpredicts RGGI leakage, for reasons we give below. However, the finding that models with differing amounts of transmission system detail produce substantially different leakage predictions is valid, and testing for such differences is the main purpose of this paper.

Table B: Effect of RGGI on Carbon Dioxide Emissions

		Year 0	Year 10	Year 20
1 Node – Policy Effect	In RGGI	-55,020,247	-48,535,057	-54,408,007
	Outside RGGI	+79,026,267	+54,287,354	+55,735,423
	Net Effect	+24,006,020	+5,752,297	+1,327,416
300 Node – Policy Effect	In RGGI	-25,433,526	-35,510,483	-49,754,186
	Outside RGGI	+36,278,990	+38,155,900	+43,329,451
	Net Effect	+10,845,464	+2,645,417	-6,424,735
5k Node – Policy Effect	In RGGI	-18,282,576	-30,869,475	-61,262,677
	Outside RGGI	+26,208,921	+33,505,346	+43,312,049
	Net Effect	+7,926,345	+2,635,871	-17,950,628

*$10 permit required for each short ton of CO_2 emissions

The smaller number of constraints in the 300-node model causes the underprediction of RGGI emissions and the overprediction of leakage by allowing more simulated generation to be imported to the RGGI states from other US states and Canadian provinces. In the 300-node model, fewer of the lines from the original 62,000-node model are retained, so fewer of them impose transmission limits in the model. Since flows distribute themselves in parallel fashion over all lines, and the 300-node model does have 216 transmission constraints representing the constraints that have bound in recent years, it was not possible to know in advance whether the effects of having fewer constraints and more equivalent lines would be large enough to make using the 300-node model problematic. This results section reports the magnitudes of some of the effects. The reader can judge whether they are large enough to be problematic. [Check for places where we imply that aggregation causes big errors in other kinds of modeling too.]

Our model probably overpredicts leakage resulting from the $10 emission price because, to remain linear, the model currently assumes transmission losses are a constant proportion of consumption. In reality, losses from a line increase approximately exponentially with flow on

the line (Kirschen and Strbac, 2004). The other models mentioned in the Introduction also do not have this feature. However, in future research, we intend to try to incorporate this non-linearity into our modeling. Experimentation and improvements in computing technology may help.

In addition, RGGI is more than just an allowance price. It appears likely that in reality the allowance price will be less than $10, and that many of the emission reductions will come about from one or two other aspects of RGGI: the investment of RGGI allowance auction proceeds in energy efficiency promotion in the RGGI states, and perhaps offsets. These other aspects of RGGI will reduce carbon dioxide emissions without causing leakage, making the overall ratio of reductions to leakage more favorable, potentially by a large margin. However, those quite different aspects of RGGI are outside the scope of this paper, which analyzes only the allowance price aspect of RGGI, since that is the aspect that can serve well as the sample policy in our paper's comparison of the predictions of grid simulation models with differing transmission detail.

If any of the nearby states or provinces adopts a policy that puts a price on emissions, or if RGGI implements leakage reduction measures, that will further reduce overall leakage from RGGI, since leakage is an increasing function of the difference in the price on marginal emissions.

Effect of emission price on electricity prices. For policymakers and economists, the effect of a policy on prices can be important. Table C shows the average wholesale price of electricity in the RGGI states by each model in each scenario and year. In each simulated year, the predicted effect of a $10 RGGI emission price on the average wholesale price of electricity in the RGGI states is 54 to 73% higher with the 5,000-node model than with the 300-node model.

The smaller number of constraints in the 300-node model causes this difference by effectively increasing the elasticity of supply of electricity imports to the RGGI states. The RGGI emission price increases the demand for imports, since they produce no emissions within the RGGI states. With more elastic import supply in the 300-node model, this demand increase has a smaller impact on the RGGI electricity price.

Table C: Annual Average Wholesale Price of Electricity (in $)

		Year 0	Year 10	Year 20
1 Node - No Policy	Non RGGI	$28.98	$39.73	$63.81
	RGGI	$28.98	$39.73	$63.81
	EI	$28.98	$39.73	$63.81
1 Node - Policy*	Non RGGI	$29.39	$40.37	$63.89
	RGGI	$29.39	$40.37	$63.89
	EI	$29.39	$40.37	$63.89
300 Node - No Policy	Non RGGI	$30.01	$39.43	$61.93
	RGGI	$28.28	$40.79	$61.83
	EI	$29.75	$39.62	$61.92
300 Node - Policy	Non RGGI	$30.22	$39.64	$61.97
	RGGI	$30.73	$43.35	$62.68
	EI	$30.29	$40.17	$62.06
5K Node - No Policy	Non RGGI	$30.06	$38.76	$60.17
	RGGI	$28.44	$42.22	$59.83
	EI	$29.93	$39.04	$60.14
5K Node - Policy	Non RGGI	$30.35	$39.08	$60.18
	RGGI	$32.62	$46.16	$61.30
	EI	$30.54	$39.65	$60.26

*$10 permit required for each short ton of CO_2 emissions

Electricity prices. Table C shows another interesting difference between the predictions of the models: In years 10 and 20, most of the prices predicted by a more-detailed model are lower than the corresponding prices predicted by a less detailed model. This deviates from the usual pattern in cost minimization that more constraints increase marginal cost. The reason for

this surprising result is that the more detailed model has more localized scarcity and abundance of generation capacity, and an asymmetry between scarcity locations and abundance locations: New entry caps the scarcity-induced price increase reasonably close to the average system-wide electricity price, but in some locations the existing generation capacity has such a low short-run average cost that local abundance can push the price well below the system-wide average. This is reflected in Figures A and B. Figure B, for the more detailed model, has much greater localized variation in prices, less area with high prices, and more area with low prices. It is also reflected in Table D, which shows that more transmission system detail is associated with more entry and less retirement. The direction of this asymmetry is a result of the particular cost data used in this paper's simulations, not an immutable characteristic of more detailed modeling.

Figure A: 300 Node Model Wholesale Price Map, Year 10, with No RGGI Policy

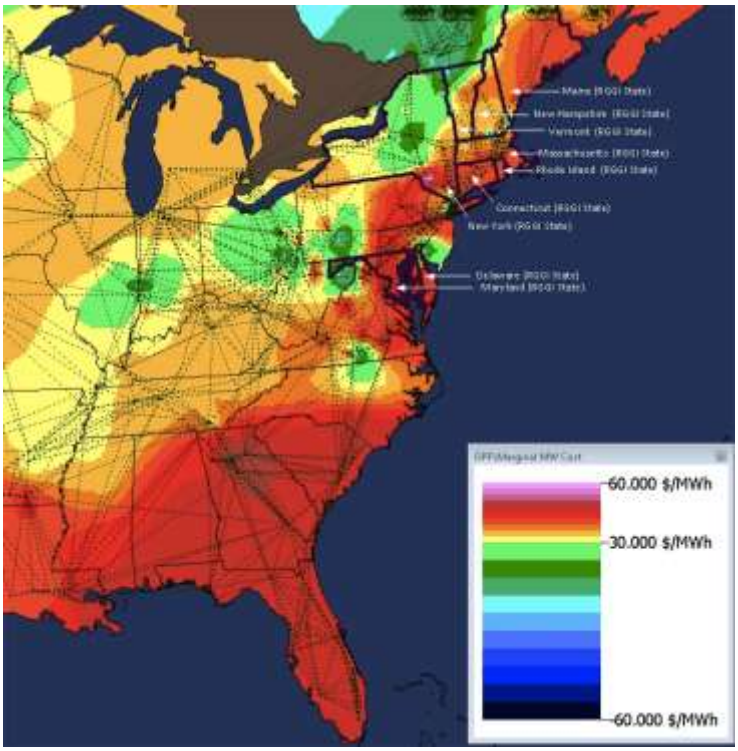

Figure B: 5000 Node Model Wholesale Price Map, Year 10, with No RGGI Policy

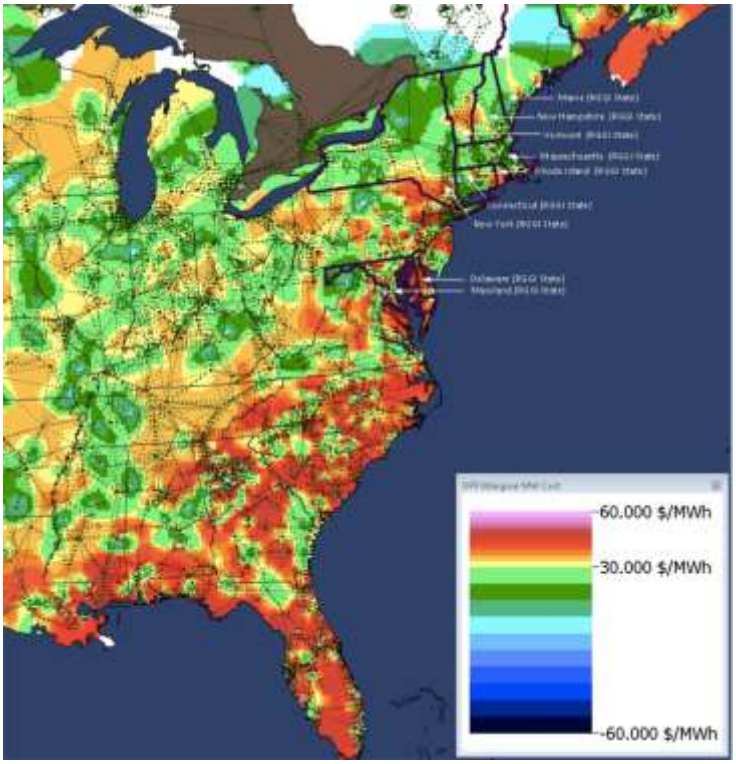

Table D: Entry and Retirement of Fossil Fueled Generation Capacity

		Entry		Retirement	
		Non RGGI	RGGI	Non RGGI	RGGI
1 Node - No Policy	Year 10	0	0	114,759	27,947
	Year 20	22,431	0	0	0
1 Node - Policy	Year 10	0	0	109,694	33,421
	Year 20	24,018	0	0	0
300 Node - No Policy	Year 10	123	0	110,498	27,208
	Year 20	30,395	1,976	0	0
300 Node - Policy	Year 10	364	0	107,590	31,112
	Year 20	33,226	1,174	0	0
5K Node - No Policy	Year 10	142	406	102,155	23,950
	Year 20	32,430	2,363	0	0
5K Node - Policy	Year 10	336	406	100,036	28,206
	Year 20	37,556	594	0	0

All entry in the model is by natural gas fueled generators. Almost all retirement is by coal, oil, and gas fueled generators.

Effect of RGGI emission price on year-20 emissions: The association between more transmission system detail, more entry, and less retirement also explains why total emission reductions in year 20 are greatest in the 5,000-node model: Compared with the other models, it has sufficiently more generation outside of the RGGI states that less generation in the RGGI states is needed, in particular during hours of low congestion. This effect dominates the greater difficulty delivering imports to the RGGI states, which is most acute during the less common hours of high congestion. The general lesson from this is that transmission system detail can drive investment decisions, which in turn can have a large impact on predicted effects of a policy or other change. The online appendix at http://shawhd.wp.rpi.edu/ presents additional results.

5. CONCLUSIONS

Recent advances in computing have made it possible to incorporate a large amount of transmission system detail in models that also predict entry and retirement of generators. However, doing so requires additional data and, for now, precludes incorporating some other kinds of computationally expensive model features such as prediction of transmission expansion. This paper demonstrates the use of a detailed network model in an economic model for predicting the effects of a policy. Very similar methods and tools could be used to predict the effects of a potential new generator or transmission line. It also tests the effect of network model simplification on policy predictions.

When it comes to estimating the consequences of energy or environmental policies in the US and other parts of the world where the ultimate effects hinge upon flows through the electric power grid, it is essential to represent that network in sufficient detail to be able to accurately

predict where congested transmission paths will occur and therefore where price (marginal supply cost) differences will arise. Only then will an accurate picture emerge about which generators will operate, where new generators will be built, and where existing units will be retired. The devil is in the details. In this analysis it was shown that a 300-node representation of the 62,013 node power grid in the Eastern Interconnection was necessary to provide the needed locational differentiation.

This level of model detail may be even more essential for other possible planning and policy analyses. One example would be the investigation of an environmental policy covering sulfur dioxide, nitrogen oxides, and fine particulate matter, whose health effects hinge crucially on the type and location of generation in relation to population centers. As shown here, those choices in turn may be determined crucially by the specific locations of network congestion and the resulting different prices for electricity. And, for an analysis of the efficacy of subsequent transmission expansion, difficult as that might be, identifying specific points of congestion and price spreads is essential, not only to pin-point impediments to reliability, but also to identify where the greatest power supply cost savings might be achieved through new line construction.

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