

North American energy system responses to natural gas price shocks

Maxwell Brown^{a,*}, Sauleh Siddiqui^b, Charalampos Avraam^c, John Bistline^d, Joseph Decarolis^e, Hadi Eshraghi^e, Sara Giarola^f, Matthew Hansen^g, Peter Johnston^h, Saroj Khanal^a, Anahi Molar-Cruzⁱ

^a United States Department of Energy, National Renewable Energy Laboratory, USA

^b American University, Department of Environmental Science, USA

^c Johns Hopkins University, Department of Civil Engineering, USA

^d Electric Power Research Institute, USA

^e North Carolina State University, Department of Civil, Construction, and Environmental Engineering, USA

^f Imperial College London, Department of Earth Science and Engineering, UK

^g Canada Energy Regulator, Canada

^h Environment and Climate Change Canada, Canada

ⁱ Technical University of Munich, Department of Electrical and Computer Engineering, Germany

ARTICLE INFO

Keywords:

Energy security
Resilience
Price shocks

ABSTRACT

As of 2020, North American natural gas extraction and use in the electricity sector have both reached all-time highs. The combination of North America's increased reliance on natural gas with a potential disruption to the natural gas market has several energy security implications. Additionally, policymakers interested in economic resiliency will find this study's results useful for informing the implications of the energy sectors' long-term planning and investment decisions. This paper evaluates how both the electricity and natural gas sectors could respond to hypothetical gas price shocks under different system configurations. We impose unforeseen natural gas price shocks under reference and alternative configurations resulting from a renewable generation mandate or variations to renewable capacity costs. Results from several different models are presented for the electricity and natural gas sectors separately for Canada, Mexico, and the United States. Generally, the US becomes more (less) reliant on electricity imports from Canada given a high (low) gas price shock but increases (decreases) exports to Mexico. The renewable mandate is demonstrated to buffer electricity price increases under high price shocks but price reductions under the low price shocks are dampened given less flexibility to take advantage of the low-priced natural gas. The United States is demonstrated to reduce natural gas production and net exports with high natural gas price shocks given a reduction in demand.

1. Introduction

From 1998 to 2018, total natural gas consumption in the US has increased by 34.6% with natural gas consumption in the US electricity sector increasing 131% over that same time period (EIA, 2019a). The primary driver of the recent natural gas boom has been the advent of hydraulic fracturing which has brought about a sharp decrease in natural gas prices and thus increased the competitiveness of natural gas with coal in the electricity sector. The electricity sector's growth of natural gas consumption over the past two decades is far greater than any other sector with residential, commercial, and industrial consumption changing by 10.0%, 15.9%, and −0.4%, respectively over the

1998–2018 time period. Although consumption of natural gas in the vehicles sector has increased dramatically (364% from 1998 to 2018), it still remains a small portion of overall gas consumption with only 0.15% in 2018 (EIA, 2019a).

Electricity and natural gas trade across the North American continent has changed dramatically over the past two decades as well. For example, US natural gas pipeline exports to Mexico have increased from 53 billion cubic feet to 1688 billion cubic feet from 1998 to 2018 (EIA, 2019b) and are expected to further increase as Mexican electricity demand is forecasted to markedly rise over the next few decades. The US imported 51% of Canadian natural gas production in 2017 (NRCAN, 2018) and imported 73 TWh of electricity from Canada in 2016 (EIA,

* Corresponding author.

E-mail addresses: maxwell.l.brown@gmail.com, maxwell.brown@nrel.gov (M. Brown).

2017). Although electricity imports make up a small-but-growing portion of US electricity consumption, they are becoming increasingly important to border regions such as New England and New York (EIA, 2017).

This recent evolution of the electricity sector towards increased reliance on natural gas and the increasing interconnectedness of North American energy markets puts the continent at risk to unexpected fluctuations in natural gas fuel prices. Historically, natural gas prices have experienced remarkable volatility and only relatively recently the world has entered the current paradigm of inexpensive natural gas. Given the potential for market disruptions that have been experienced before, this paper seeks to answer: “How could the North American natural gas and electricity sectors respond to unforeseen and sudden changes in the price of natural gas under different buildout configurations?” We answer this question using several different models which depict either the macroeconomic equilibrium or the bottom-up investment and operational decisions for the electricity and natural gas sectors.

The research exploring energy security and responses to fuel price shocks is extensive but has primarily focused on oil markets while being and been econometric in nature (Huntington, 2005; Jones, Leiby and Paik, 2004; Kilian, 2009; 2010; 2014; Lescaroux and Mignon, 2008; Park and Ratti, 2008; Stern, 1993). Those that have been simulation-based (Coen and Hickman, 1983; Uría-Martínez, Leiby and Brown, 2018), as opposed to econometric, have again focused on shocks to oil markets. The general consensus among these studies is that shocks to oil prices result in a negative impact on the economies of countries that are net importers of oil (Oladosu, Leiby, Bowman, Uría-Martínez and Johnson, 2018). Therefore, responses from and resulting net benefits for each country will largely depend on its balance of trade for natural gas as well as the relative sizes of the country’s energy sectors. Each of the countries modeled in this study has starkly different position in trade; for example, Canada is a net exporter of natural gas whereas Mexico is a net importer and exports very little natural gas (NACEI, 2019). The US has historically been a net importer of natural gas but recently has become a net exporter, with 67% of its pipeline exports destined for Mexico in 2018 (EIA, 2019). With the macroeconomic representations, this study elucidates the overall economic impact of these shocks in terms of Gross Domestic Product (GDP). In contrast, the partial equilibrium, bottom-up models of electricity and natural gas sectors provide more detailed insights to the technological responses to gas price shocks with less resolved representations of macroeconomic feedbacks.

To the best of our knowledge, no study to date has been simulation-based while focusing on the interactions of natural gas and electricity markets with unforeseen disruptions in natural gas prices. The findings from this study will be useful to policy makers and industrial participants that are interested in the economic resiliency and associated long term planning decisions inherent in their energy sectors. The paper is structured as follows. The next section, *Methodology*, provides brief overviews of the models used in this study; although descriptions are brief, the section also includes sources to find more information on each model. The *Scenario Design* subsection describes how the shocks are implemented as well as the various policy and assumption modifications to create the four system configurations. The *Results* section presents results separately for each country and sector in turn then covers international trade across the North American continent. Finally, we present the overall implications of the study as well as the caveats and areas for further research in the *Discussion* section.

2. Methodology

This section is broken into two parts. The first subsection contains a brief overview of the models used in this study; more information on the models can be found in the leading article to this article’s special issue as well as in the references provided. The second subsection serves to describe the scenario design and shock implementation.

2.1. Model descriptions

This subsection serves to provide a broad overview of the models used in this study; more detailed information on each model is available through the models’ referenced documentation and in the supporting information of this special issue. Table 1 below lists the models used in this study and the subsequent paragraphs provide a brief description of each model in turn as well as references to find more information.

ECCC’s multi-sector multi-regional (EC-MSMR) model is an open-economy recursive-dynamic CGE model of the global economy, formulated in MPSGE (mathematical programming system for general equilibrium). There are 16 regions, 20 basic commodity-producing sectors and three final demand sectors (consumption, governmental spending, and investment) in the model aggregated from Global Trade Analysis Project Database version 9. Of the 20 commodity-producing sectors, electricity sector is split into power generation, transmission and distribution. Power generation is composed of various technologies: (1) fossil fire, (2) nuclear, (3) hydro, (4) wind, (5) solar, (6) geothermal, (7) biomass, (8) coal integrated gasification with carbon capture, (9) natural gas power generation with carbon capture, (10) biomass power generation with carbon capture, and (11) solar power generating with storage. The last 4 electricity generation technologies are backstop electricity generation technologies that may be activated in the presence of climate policy. There are also three non-electric Backstop Fuel Technologies implemented in the model: (1) biomass to liquid, (2) H2 supply, and (3) renewable natural gas which can be substituted for fossil energy use (Ghosh, Luo, Siddiqui and Zhu, 2012; Zhu, Ghosh, Luo, Macaluso and Ratray, 2018). For more information on EC-MSMR, see Ghosh et al. (2012) for the algebraic formulation and Zhu et al. (2018) for detailed background information.

MUSE, the ModUlar energy systems Simulation Environment, is a global simulation model which simulates the whole energy system, including demand, transformation/conversion, and supply sectors. The demand sectors are:

- industry which includes the five most energy intensive subsectors (pulp and paper, iron and steel, cement, aluminium, chemicals) with a total of 201 technologies
- agriculture which includes food, vegetables, forestry, and bioenergy production with a total of 25 technologies
- commercial and residential buildings which include heating, cooling, cooking, lighting, and conditioning systems used in services and households with a total of 143 technologies

The transformation sectors are characterized by:

- the power sector which includes the power stations (coal, oil, gas, biomass) based on conventional and CCS-retrofitted processes; renewables (hydropower, tidal, wind, geothermal energy)
- refineries which produce conventional fuels, biofuels, aviation bio-fuels and hydrogen and include a total of 30 technologies

The supply sectors in MUSE are based on exogenous supply curves for nuclear, coal, wastes, oil, and associated gas. Non associated gas is modeled through a profit-based dynamic supply curve approach (Crow, Giarola and Hawkes, 2018).

MUSE sectors are modeled as individual modules where drivers for investment decisions and operations reflect the decision making of key players in each sector using an agent-based modelling approach (Sachs, Meng, Giarola and Hawkes, 2019). In the power sector the decision rule for new investments and operations applies a merit order approach based on minimum cost.

Each sector interacts with the rest of the energy system though a partial equilibrium framework, offered by a market clearing algorithm which balances each energy commodity supply and demand (Giarola, Crow and Hawkes, 2019). The market uses a dynamic recursive

Table 1
Model characteristics.

Model Acronym	Institution	Model Type ^a	Energy Sectors Represented ^b	Canada	Mexico	USA
EC-MSMR	Environment and Climate Change Canada	CGE	All Major	X	X	X
MUSE	Imperial College London	IAM, Partial Equilibrium	All Major	X	X	X
NANGAM	Johns Hopkins University	MCP, Partial equilibrium	Natural Gas	X	X	X
NEB-EFMS	National Energy Board (Canada) ^c	CGE	All Major	X		
ReEDS 2.0	National Renewable Energy Laboratory	LP	Electricity	X	X	X
TEMOA	North Carolina State University	LP	All Major			X
urbs-MX	Technical University of Munich	LP	Electricity		X	

^a CGE: Computable General Equilibrium; MCP: Mixed Complementarity Problem; LP: Linear Program; IAM: Integrated Assessment Model.

^b 'All major' energy sectors designates natural gas, coal, and oil as well as their conversion to electricity and petroleum-derived products.

^c As of August 28, 2019, the National Energy Board became the Canada Energy Regulator.

algorithm to match supply and demand in an imperfect foresight temporal simulation approach where the forward price and demand trajectories are known to investors for a limited number of future years. The intermittency of the electric output from renewables is described through aggregated capacity factors obtained from a detailed spatially explicit analysis which integrates the methodology described in (Bosch, Staffell and Hawkes, 2017). The electricity demand is an aggregation of the sectors demand endogenously calculated following seasonal (three seasons) and diurnal load shapes for a total of 30 time slices. Specifically, three seasons (winter, spring-autumn, summer), four slices in a day (night, morning, afternoon, evening time slices), and two additional demand peaks during weekdays are modeled.

The North American Natural Gas Model (NANGAM) is an inter-temporal, bottom-up, partial-equilibrium model that simulates natural gas infrastructure decisions in North America (Feijoo, Huppmann, Sakiyama and Siddiqui, 2016; Feijoo et al., 2018). It comprises of the 9 census regions of the US and a region that accounts for Alaska and Hawaii, 2 regions for Canada, 5 regions for Mexico and a Rest Of World region. Between the 18 regions there exist 69 representative pipeline connections. The capacity and investment cost of the representative pipeline connections are based on 778 active projects and 187 new ones that account for a total of 45,791 miles of pipeline projects. Representative producers and pipeline operators are assumed to be inter-temporal profit maximizers. The representative producer in each region decides on optimal natural gas production and capacity expansion, while pipeline operators decide on optimal trade between regions and expansion of pipeline capacity. The model thus includes the Karush-Kuhn-Tucker optimality conditions of all producers and traders, coupled with market equilibrium conditions and is formulated as a Mixed Complementarity Problem (MCP) with a stochastic extension also available for analysis (Sankaranarayanan, Feijoo and Siddiqui, 2018).

Production and transportation costs for the US are retrieved from the U.S. Energy Information Administration (EIA); for Canada from the National Energy Board (NEB) of Canada; and for Mexico from SENER. NANGAM runs in 5-year time steps until 2050. Reference production, consumption and inter-regional trade projections for the time horizon are retrieved from the Annual Energy Outlook 2017 (EIA, 2016) for the US (*Annual Energy Outlook, 2017 with projections to 2050*, 2016), from Canada's Energy Future 2016 report for Canada (National Energy Board, 2016), and from the Mexico Natural Gas Outlook 2016 for Mexico (SENER, 2016). The model is then calibrated to match reference data. NANGAM is written in GAMS and is based on the Multimod framework (Huppmann and Egging, 2014).

The National Energy Board's Energy Futures Modeling System (NEB-EFMS) is a multi-model framework used to develop the energy supply and demand projections found in the NEB's *Canada's Energy Future* series of outlooks. Natural gas production projections are primarily based on an NEB-developed deliverability model for the Western Canadian Sedimentary Basin that estimates future production based on various inputs including detailed historical well data, assumed prices and revenue reinvestment, drill day cost, well productivity, and LNG exports. Electricity generation and energy use projections are made using the

NEB-EFMS model, developed by Systematic Solutions Inc. NEB-EFMS is a system dynamics model where detailed energy use by type, economic sector, and region in Canada interacts with an electric supply simulation for each region. Key inputs include energy prices, energy supply projections, technology costs, policy parameters, and macroeconomic projections which are provided by Stokes Economics.

The revised Regional Energy Deployment System (ReEDS 2.0) models electricity transmission, capacity, and generation across Canada, Mexico, and the USA. The model seeks to minimize the costs of investment and operations in the electric power sector. ReEDS 2.0 includes 205 power balancing regions which balance electricity supply and demand through generation and transmission. Hydropower, concentrated solar power (CSP), utility scale photovoltaic (PV), distributed PV, onshore wind, offshore wind, and geothermal capacity expansion costs are represented through supply curves that entail the cost of connecting the resource to the nearest grid entry point; CSP and wind capacity supply curves are represented in 454 further subregions. ReEDS 2.0 includes a detailed depiction of the challenges associated with renewable integration and the valuation of grid services for variable renewable energy technologies, namely the curtailment and capacity credit attributed to each energy technology. The '2.0' indication is to distinguish the model from its former version since it has been re-written from scratch starting in 2018; the revised model's code and data for the US is publicly available.¹ More information on the model representation can be found in Brown et al. (2020).

Tools for Energy Model Optimization and Analysis (Temoa) is an open source energy systems optimization model. Temoa is formulated as a linear program that minimizes the total system cost of energy supply over the user-specified time horizon,² subject to both system-level and user-defined constraints. System-level constraints include conservation of energy at the individual process level, the global balance of commodity production and consumption, and the satisfaction of end-use demands. User-level constraints include emission limits, maximum technology growth rates, and bounds on technology capacity and activity. Temoa minimizes the total system-wide cost of energy supply by optimizing the installation of new capacity and utilizing both new and existing capacity to meet demand over a user-specified time horizon that typically spans multiple decades. The time horizon is split into a user-defined number of time periods, which represent a bundled set of years. The results for each year within a given time period are assumed to be identical. To represent intra-annual variations in energy supply and demand, the model balances energy commodity flows across a set of user-defined time slices, which represent different combinations of seasons and times of day. The complete algebraic formulation of Temoa is presented in (Hunter, Sreepathi and DeCarolis, 2013) with updates provided in (DeCarolis, Hunter and Sreepathi, 2018). The input

¹ See <https://www.nrel.gov/analysis/reeds/> for more information.

² Note that the intertemporal nature of the Temoa model does not allow for an unexpected increase in fuel prices without significant modifications; therefore, the Temoa shocks in this analysis are foreseen.

database used in this analysis represents the US energy system by the nine US Census Divisions, with electricity trade allowed between the regions. Patankar et al. (2019) provides full documentation of the database (Patankar, Eshraghi, Nagarajan and DeCarolus, 2019).

urbs-MX is a nine-region model of the Mexican power system based on urbs, an open-source linear optimization modeling framework for capacity expansion and unit commitment analyses (TUM ENS, 2019). The model minimizes the annual system costs which comprise all investment costs by their annualized depreciation as well as the operational and environmental costs. As a result, the least-cost portfolio of generators, storage and transmission that meet the exogenously-defined electricity demand at every hour of the modeled year under capacity and environmental constraints is deterministically calculated. Furthermore, it allows the integration of multiple input and output commodities resulting in a detailed representation of the energy conversion processes. urbs-MX considers 17 power generation technologies, out of which 6 use renewable sources. These include, bioenergy, geothermal energy, hydropower with reservoir, run-of-river hydropower, onshore wind power and utility-scale photovoltaics. Additionally, two storage technologies, namely pumped-storage plants and lithium-ion batteries are included. A high temporal resolution of 8760 h per year is used to ensure the chronological tracking of storage and the detailed matching of intermittent supply and electricity demand. More information on the model can be found in (Molar Cruz, Guillén and Hamacher, 2018).

2.2. Scenario design

Each model is run for variations in system configurations that are the result of either policy or technology assumptions. Specifically, there are four different system configurations: Reference, Low Renewable Technology Costs, High Renewable Technology Costs, and a Renewable Mandate. The Low and High Renewable Technology Costs configurations adjust the costs of capacity for wind and solar technologies based on the 2018 Annual Technology Baseline (Vimmerstedt et al., 2018); the Low Technology Costs reflect the ‘low’ case as indicated by the ATB whereas the high costs reflect the ‘constant’ case as indicated by the ATB.³ The Renewable Mandate is modeled after the 34th Energy Modeling Forum’s specification that requires renewable generation to satisfy 30% of electricity consumption in 2020 and increasing linearly to 60% by 2050.

For reference, the scenarios names, abbreviations, and descriptions are presented in Table 2 below. Note that the appended ‘High’ and

Table 2
Reference scenario design.

Name	Abbreviation	Setup
Business-as-Usual	BAU	Each model’s unaltered market conditions and assumptions
Renewable Mandate ^a	RenMandate	Renewable generation to meet 30% of electricity consumption in 2020, increasing linearly to 60% by 2050
High Renewable Capacity Costs	HighRenCost	High Renewables cost for wind and solar technologies as represented through the ‘constant’ case from ATB 2018
Low Renewable Capacity Costs	LowRenCost	Low Renewables cost for wind and solar technologies as represented through the ‘low’ case from ATB 2018

^a The renewable mandate in this study is for exemplary purposes only and is modeled after the 34th Energy Modeling Forum’s scenario design.

³ Although unrealistic to have constant costs for renewable capacity throughout time without significant policy or other intervention, the high renewable costs scenario is intended to act as an extreme scenario for low renewable deployment.

‘Low’ to any of the four case names indicates the case being shocked to the high and low gas price trajectory, respectively. Finally, there is a key distinction between the ‘BAU’ and ‘reference’ declarations; ‘BAU’ indicates the models’ base conditions without any modifications to policy or fuel prices whereas ‘reference’ indicates the shock cases’ respective reference case. For example, the ‘reference’ case for the *RenMandate_High* shocked case is the *RenMandate* case.

Although all models in this study rely on several different sources for input data, natural gas prices and price trajectories are from the 2019 Annual Energy Outlook (*Annual Energy Outlook, 2019 with projections to 2050*, 2019) and its associated *Reference* scenario which is shocked to the AEO’s *High Oil and Gas Resource* (HOG) and *Low Oil and Gas Resource* (LOG) cases. The shocks are implemented similarly across all models – the system will be solved up until the earliest modeled year before 2030 under the assumption that gas prices will remain at the AEO’s *Reference* scenario levels and then, in 2030, gas prices are either raised or lowered consistent with either the AEO 2019’s HOG or LOG cases. Fig. 1 presents the gas prices as modeled in the Reference and either of the high or low price shock cases as well as the capacity cost assumptions by technology (PV and wind) and scenario (Mid, Low, High). Natural gas prices delivered to the electricity sector increase by 24.2% in the LOG shock case and decrease by 19.3% in the HOG shock case relative to the reference case in 2030. Although Uribe-Martinez et al. (2018) impose a shock that lasts only five years, the discrepancies in models’ represented years makes a consistent shock length difficult; therefore, the adjustments to natural gas prices persist through the end of the modeling horizon.

An exception to this scenario design is in NANGAM’s representation. For these scenarios, the quantity of natural gas consumed in the electricity sector from ReEDS 2.0 is communicated to NANGAM in a one-way linkage. NANGAM uses those quantities specific to the electricity sector to compute the percentage change in natural gas demand compared to the baseline scenario and update NANGAM’s regional demand by a shift in the demand curve. NANGAM is then run to produce a new set of results based on the updated demand levels.

3. Results

Of the differences across models, regions represented presents a clear distinction; therefore, we present results for each country and sector in turn then summarize findings for all countries in the discussion section. Results for the electricity sector focus on each country’s generation profile, electricity prices,⁴ country-level net exports, and system cost impacts to the two price shocks and under the various system configurations. Natural gas results will focus primarily on prices, extraction, and net exports. As a note, we choose to present 2030 in the electricity generation total and difference plots as it presents a summary of the immediate response of the electricity system; the same plots by year and model are presented for Canada, Mexico, and the USA in Appendices A, B, and C, respectively.

3.1. Canada electricity

A summary of the models’ electricity generation profiles in 2030 is presented in Fig. 2 with additional figures available as Figure 11, Figure 12, and Figure 13 in Appendix A. Note that the first row of Fig. 2 presents the total amount of 2030 generation under the Reference case whereas the next two rows contain the difference-from-Reference for the respective *High* and *Low* gas price shock case. Each model has a high

⁴ The models used in this study have varying representations of electricity price. For ReEDS 2.0 and urbs-MX, the price presented in this work is considered a wholesale price, akin to the marginal cost of power generation. For NEB-EFMS, the price is considered a market price for the electricity sector, similar to a retail price.

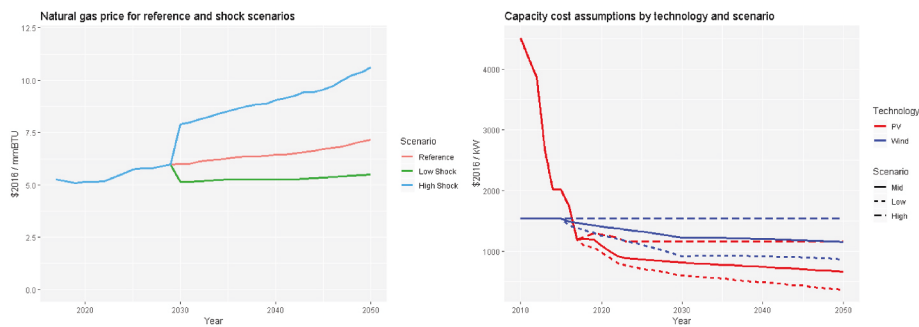


Fig. 1. Natural gas and capacity cost assumptions.

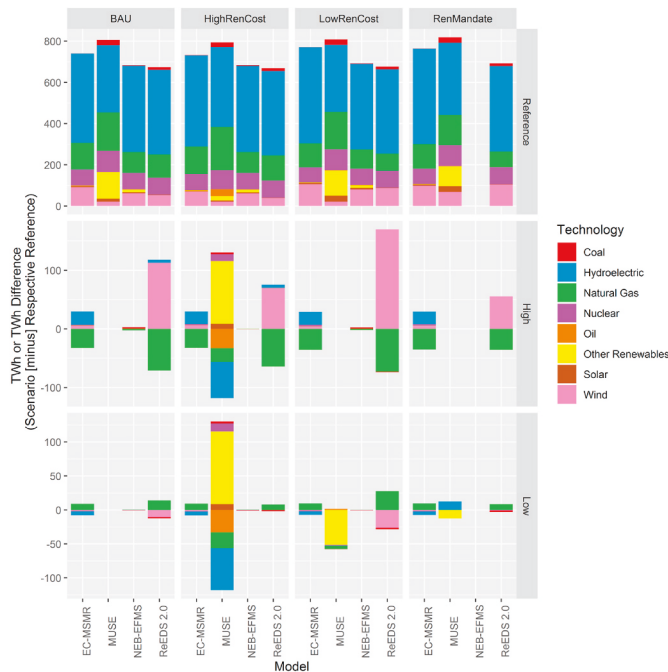


Fig. 2. 2030 Canadian generation by technology and difference from respective reference case.

proportion of electricity generation from hydropower in Canada starting in 2015 with natural gas and wind generation increasing most prominently into the future under the BAU scenario for all but the MUSE model which sees a greater increase of natural gas relative to 2015 than the other models as well as a blend of solar, wind, and other renewables at the expense of hydroelectric power. While NEB-EFMS and EC-MSMR estimate persistence of nuclear generation through the end of their time horizons, MUSE and ReEDS 2.0 do not. For MUSE, nuclear retirements are based on plants age profile. However, while base year plants are constrained to a minimum generation value, this does not apply to the new installations which will follow a mere merit order approach. ReEDS 2.0 enforces lifetime retirements of plants based on plants' lifetimes and thus, by 2042, nuclear generation in Canada is replaced by wind. All models see a small and diminishing amount of coal generation in all scenarios which is largely unaffected by the adjustments to renewable costs or the imposition of the renewable mandate.

In comparison to the BAU case, the other reference cases typically see a substitution of gas for wind and *vice versa* depending on the impact of the case's assumptions on the relative competitiveness of each technology. One exception is that EC-MSMR estimates an increase in hydroelectric generation relative to the BAU scenario under all other reference cases given the inherent structure of CGE models' constant elasticity of substitution functions and their lacking portrayal of explicit

capacity limits. MUSE has greater diversity in its changes to the generation portfolio than other models. Under the HighRenCost scenario, MUSE estimates an overall increase in Wind and Other Renewables at the expense of solar, oil, and gas. Under the LowRenCost scenario, MUSE increases solar and wind at the expense of oil and gas technologies. The largest relative change is specific to ReEDS 2.0 under the LowRenCost scenario where wind generation is approximately 150 TWh greater relative to the BAU case by 2050.

When faced with the *high* natural gas price shock (the first row of plots in Figure 13), the models respond similarly downwards in that they all, expectedly, reduce generation from natural gas. The average response across all models is a reduction of 53.2 TWh in 2030, the majority of which is from natural gas generation except for MUSE which sees a reduction in generation from oil technologies as well. Which technologies substitute for the decrease in gas-based generation depends on the model. EC-MSMR responds through increased generation from hydroelectric and wind generation technologies whereas MUSE and ReEDS 2.0 respond with an increase in primarily wind generation with lesser amounts of solar generation. The impact on total generation varies by model and is presented by shock scenario in Table 3. EC-MSMR consistently estimates a reduction in total Canadian generation under the *high* shock case and an increase in generation under the *low* shock case. In contrast, MUSE and ReEDS 2.0 estimate the opposite impacts of increased Canadian generation under the *high* shock case but have varied reactions under the *low* shock case. The largest absolute impact on total Canadian generation are with ReEDS 2.0 under the LowRenCost scenario's *high* shock case; primarily driven by increased Canadian net exports to the USA.

When faced with the *low* natural gas price shock (second row of plots in Figure 13), all models respond similarly in that they increase generation from natural gas. The displaced technologies are nearly symmetrical to the *high* shock case with EC-MSMR responding with a mix of hydroelectric and wind generation, ReEDS 2.0 with wind generation, and MUSE responding with a mix of different technologies. Total Canadian generation increases in two thirds of the *low* shock cases. There is an interesting implication in the shape of the generation portfolio change under the ReEDS 2.0 responses to the *low* shocks. The retiring

Table 3

Change in total Canadian generation by shock case relative to respective reference scenario (TWh).

	BAU	HighRenCost	LowRenCost	RenMandate
High				
EC-MSMR	-2.8	-2.4	-6.7	-5.6
MUSE	0.0	12.2	0.0	0.0
NEB-EFMS	0.6	-0.5	0.5	NA
ReEDS 2.0	46.8	11.4	95.9	19.8
Low				
EC-MSMR	1.1	1.1	2.0	1.8
MUSE	0.0	12.1	-56.3	-0.1
NEB-EFMS	-0.5	-0.5	-0.6	NA
ReEDS 2.0	1.9	6.4	-1.0	5.4

Canadian generation capacity in the later years of the simulations is replaced with natural gas generators as opposed to when wind replaces retired capacity under the reference and *high* shock case.

The changes in Canadian electricity price in response to shocks are presented in Fig. 3; it is important to note that the differences are reported with respect to each reference case and thus reflect the relative price change within each system configuration. The price responses under the LowRenCost scenario are notably lower than the other cases under the *high* price shocks but there is no discernable difference from BAU under the *low* shock cases for the same scenario. For ReEDS 2.0, the HighRenCost scenario sees the greatest price increases under the *high* price shock but the greatest price decrease under the *low* shock case as the HighRenCost case implies the greatest buildout of Canadian natural gas capacity and thus there is more sensitivity to and correlation natural gas prices. The RenMandate scenario is estimated to have the least decrease in price under the *low* shock case as Canada is unable to fully exploit the lower-priced natural given the requirement to generate from renewable energy technologies.

The impacts of natural gas price shocks on Canadian electricity net exports vary by model as presented in Figure 14. Net exports decrease (increase) under the *high* (*low*) shock cases under all scenarios for the EC-MSMR model. NEB-EFMS estimates minimal changes to electricity exports under the shock cases. ReEDS 2.0 consistently estimates an increase in Canadian net exports under the *high* shock case with the greater reaction under the LowRenCost scenario where increased Canadian wind generation is more attractive for export to the USA who has become more reliant on natural gas generation. Electricity net export responses to *low* shocks are typically on par with each reference case with the exception again under the LowRenCost scenario where a low gas price clearly reduces Canadian net exports of electricity.

3.2. Canada natural gas

The advantage of a multimodel comparison comes across when looking at Natural Gas production and export results under the different scenarios as presented in Fig. 4. Under the price-driven NEB-EFMS model, high natural gas prices drive higher production and higher exports. From a modeling perspective, assuming the Canadian market isn't large enough to impact global and US natural gas prices, this makes sense as Canada sets up to export Natural Gas to the US. NANGAM, on the other hand, is a purely natural gas model that takes electricity demand as exogenous but has endogenous changes in natural gas prices. Under the high gas price scenario, NANGAM responds to the lower demand for electricity across North America by reducing production, but still maintaining some exports. The shock is driven by what happens in the electricity sector, as opposed to the natural gas sector. In the opposing scenario, lower prices drive lower production and lower exports in NEB-EFMS, although the impact isn't as great as in the higher

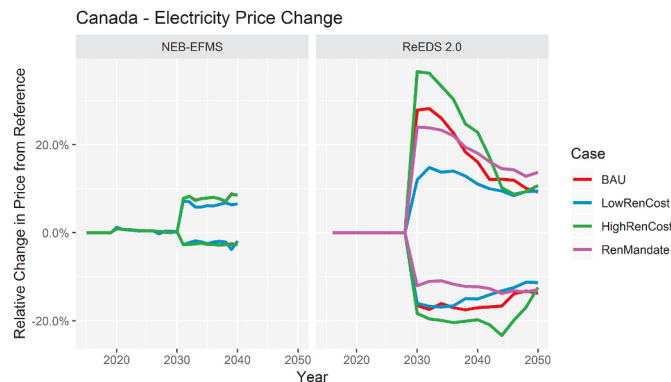


Fig. 3. Change in wholesale Canadian electricity price relative to respective reference case.

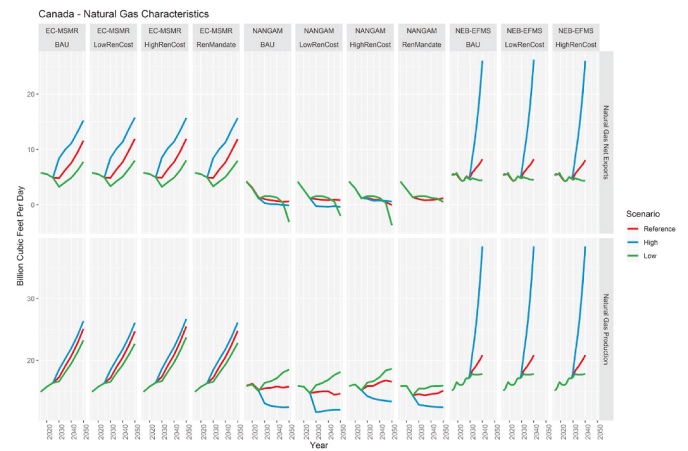


Fig. 4. Canadian natural gas net exports and natural gas production.

price scenario. Exports decrease at a higher rate than production, indicating that this scenario increases the Canadian consumption of natural gas. NANGAM also shows an increase in local Canadian consumption, as exports of natural gas initially rise, but fall in the long term, especially under higher renewable costs. This is in line with the assumption that in the longer-term, switching over to natural gas and renewables will happen across North America, and these commodities can behave as complements in the short run and substitutes in the long run. Short-term and long-term production though, are relatively higher in NANGAM, indicating that lower natural gas prices lead to an increase in demand for natural gas in the electricity sector.

3.3. Mexico electricity

The 2030 Mexico electricity generation portfolio is presented in Fig. 5 as well as over the modeled time periods in Figure 15, Figure 16, and Figure 17 in Appendix B. Across all models and scenarios, natural gas plays a significant role in the estimated future of Mexico's electricity sector but its majority share is diminished by 2050 in all but the *high*

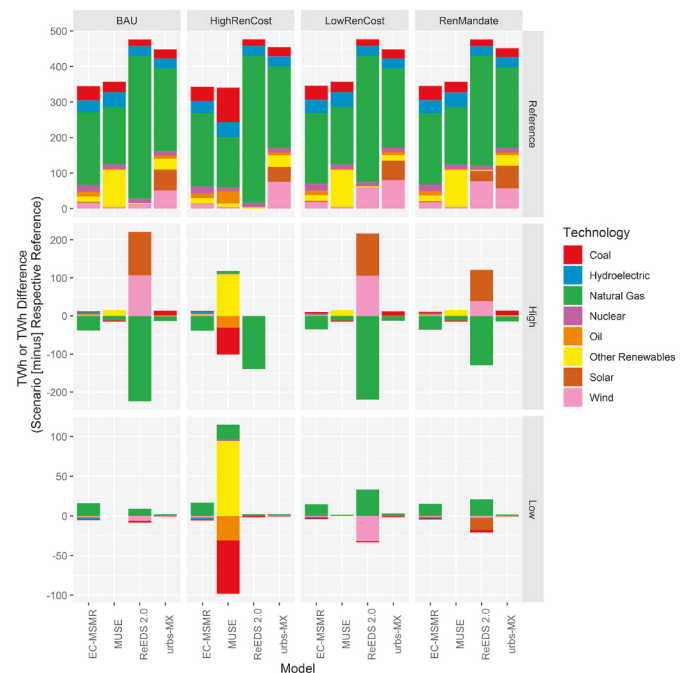


Fig. 5. 2030 Mexican generation by technology for reference cases and differences from respective reference cases for shock cases.

shock cases for ReEDS 2.0 and MUSE but persists until the end of the modeled time horizon with EC-MSMR. In contrast to Canada, wind and solar technologies are the most responsive to system configuration adjustments in Mexico. EC-MSMR estimates the most responsiveness in coal generation across the different models but, similar to the Canadian results, estimates an increase in hydroelectric generation in either the LowRenCost or RenMandate reference scenarios. Although the 2050 share of renewable generation in Mexico is similar between MUSE and ReEDS 2.0, the former favors wind whereas the latter favors solar, with an expeditious buildup of capacity buildout over the 2030–2050 time frame. The 2030 and 2050 shares of renewables in Mexico are greatest under the RenMandate scenario and least under the HighRenCost scenario for all models.

The responses to shocks of generation in aggregate and by technology varies across models. EC-MSMR typically responds with by increasing (decreasing) coal, hydroelectric, and oil generation in response to the high (low) price shocks. With MUSE, Mexico shows generally little effects of price variations: the majority of the initial stock still operates during the full simulation time with a minimum load constraint. A high gas shock shows a delayed substitution of gas with solar and wind in the BAU. Low gas price shows higher variations in the HighRenCost and RenMandate whereas gas, wind and solar substitutes for other renewables (such as biomass and geothermal) after 2030. ReEDS 2.0 responds by increasing wind and solar generation in response to the high price shock and decreasing wind, solar, and coal generation in response to the low price shock. The urbs-MX model is unique in that it responds by displacing gas generation with coal generation under the high shock case. Although there appears to be minimal response of generation under the HighRenCost scenario's low price shock, Mexico is almost entirely generating electricity from natural gas and thus there is little room to increase beyond a nearly-100% share.

Although gas and a model-dependent myriad of technologies move in opposite directions in response to the shocks, they are not equal displacements. As evident in Table 4, total electricity generation in Mexico is consistently reduced under the high shock case across the ReEDS 2.0 and EC-MSMR models whereas MUSE does not estimate a significant difference but also does not represent international transmission. The opposite is true for EC-MSMR where total Mexican generation increases with the low gas shock with MUSE and ReEDS 2.0 having lesser but inconsistent responses. EC-MSMR allows for price-responsive demand and thus there is a combination of substitution to other sources of energy as well as a reduction in the total amount of electricity consumed. ReEDS 2.0 has inelastic demand and thus any reduction in total generation would need to be met through reduced net electricity exports. Notably, the relative magnitude of responses in percent of total generation terms is greater for Mexico than for Canada and the USA.

The change in Mexican electricity price from respective reference cases is presented in Fig. 6. Relative to Canada, Mexico experiences slightly greater increases of electricity price under the high shock cases but of similar magnitude under the low shock cases. Again, the largest

Table 4

Change in total Mexican generation by shock case relative to respective reference scenario (TWh).

	BAU	HighRenCost	LowRenCost	RenMandate
<i>High</i>				
EC-MSMR	−25.8	−25.9	−25.6	−25.5
MUSE	0.0	16.9	0.0	0.0
ReEDS 2.0	−3.5	−139.6	−3.0	−8.3
urbs-MX	−0.1	−0.3	−0.2	−0.6
<i>Low</i>				
EC-MSMR	10.7	11.0	10.4	10.5
MUSE	0.0	16.8	1.1	0.0
ReEDS 2.0	0.5	0.1	0.1	0.1
urbs-MX	1.0	1.0	1.3	0.9

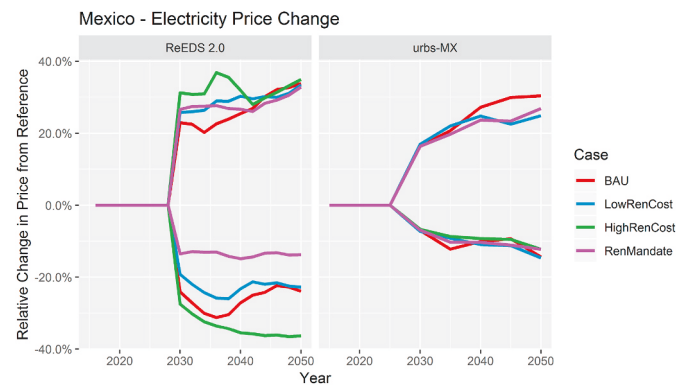


Fig. 6. Change in wholesale Mexican electricity price relative to respective reference case.

2030 electricity price increase under the high shock is with the HighRenCost system configuration due to Mexico's greater dependence on natural gas relative to other cases as well as the increased cost of substitute generation technologies. The BAU case has the least relative price increase under the high shock case as it offers a mix of less dependence on gas as well as unutilized renewable capacity development. The least price decrease under the low shocks is with RenMandate as the mandate is still binding and thus Mexico, like Canada, is not able to exploit the lower-priced natural gas given the necessity to generate from renewable sources.

Unlike Canada, the response of Mexican net electricity exports is generally consistent across models. For all models and system configurations, Mexican net electricity exports decrease (increase) in response to the high (low) gas price shock. In all but the HighRenCost case, net exports as estimated by ReEDS 2.0 continue to decline, although non-monotonically, after 2030 to a minimum amount of −17 TWh in the LowRenCost scenario. Under the low gas price shock, Mexico is estimated by EC-MSMR to have positive, although small, electricity net exports by 2050.

3.4. Mexico natural gas

Mexico remains a net importer of natural gas across all scenarios and all models as presented in Fig. 7. Under high natural gas prices, Mexico imports less than the reference case, driven by lower electricity demand in NANGAM, and a higher external price in EC-MSMR. This effect is exacerbated under lower renewables cost, which gives Mexico an alternative to natural gas for satisfying electricity demand in the long-term. Under low natural gas prices, the opposite impact happens, with

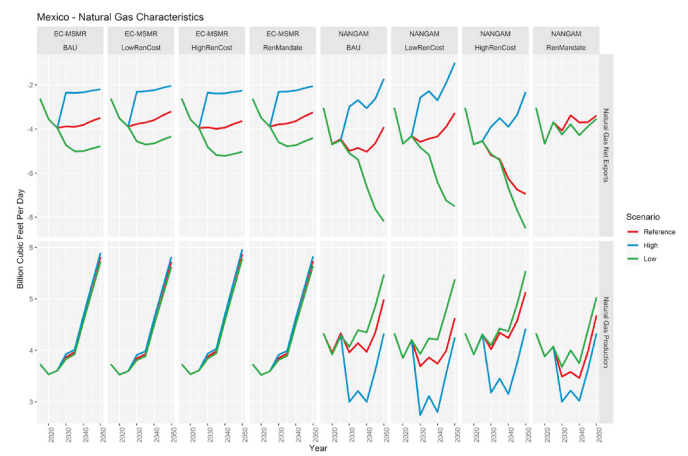


Fig. 7. Mexican natural gas net exports and natural gas production.

Mexico importing more natural gas and switching over to producing electricity from natural gas in the long term. Higher renewable costs exacerbates this effect as well. Production is more nuanced, with higher natural gas prices decreasing electricity demand, and thus decreasing production. Lower renewable costs drives production lower, while higher renewable costs mitigates some of the impact. Lower natural gas prices lead to an increase in production due to increased demand for natural gas, and an increase in exports, showing how Mexico demand for natural gas is expected to robustly increase in the long run under all scenarios.

3.5. USA electricity

Electricity portfolios for the USA in 2030 are presented by model, system configuration, and shock case in Fig. 8 below with supplementary figures which detail the electricity sector evolution over time in Figure 19, Figure 20, and Figure 21 in Appendix C. The models contrast against each other in that one sees steady increases in gas with lesser amounts of renewables (EC-MSMR) whereas the others estimate a static amount of gas through 2050 with increases in wind and solar generation. There is general agreement in the differences from the BAU case for the other system configurations. The HighRenCost scenario results in a decreased amount of solar and wind generation with the exception for ReEDS 2.0 in the later years where wind turbines are refurbished at a greater rate than under the BAU scenario. The LowRenCost scenario primarily results in increased wind generation, especially in the near term, with the greatest penetration being with the Temoa model where wind generation is increased by 763 TWh relative to the BAU case in 2030. The RenMandate setup results in a reduction of coal and gas and increases in solar and wind generation that is consistent across all models; the competitiveness of wind and solar depends on the model's assumptions and representations towards each technology including the representation of complementary technologies such as energy storage.

Unlike Canada and Mexico, coal is responsive to price shocks across all scenarios and models in the USA. Notably for EC-MSMR, coal is much more responsive than other technologies, either upward or downward in the *high* and *low* price shocks, respectively. ReEDS 2.0 and Temoa respond similarly only in the BAU scenario under the *high* gas price

shock with Temoa being more responsive in total generation than ReEDS 2.0. Temoa and ReEDS 2.0 have an interesting contradiction across the LowRenCost and RenMandate *high* gas price shock cases. Under LowRenCost, ReEDS 2.0 increases wind and solar generation whereas Temoa primarily increases coal generation with lesser amounts of wind and very little solar. The opposite is true under the RenMandate scenario where ReEDS 2.0 increases coal generation and Temoa increases coal, wind, and solar generation. Both of these situations are the result of the models' system buildout up to that point where under the LowRenCost (RenMandate) scenario, Temoa (ReEDS 2.0) hastens the deployment of renewable technologies and thus the technology on the margin becomes coal. In general, the high price shocks lead to a more heterogeneous mix of technologies in response to the price change than the low price shocks with high price shocks resulting in an increase of coal, wind, and solar whereas the low price shocks resulting in a substitution of coal for gas.

Differences in 2030 total US generation from the respective reference cases is presented in Table 5. For all models except MUSE, total US generation decreases under the *high* shock case with the largest responses being estimated by EC-MSMR. These shortfalls are typically met by increased imports from Canada with lesser responses of increased Mexico exports. Total US generation varies by model under the *low* price shock. Both EC-MSMR and Temoa estimate an increase in total US generation under the *low* price shock but MUSE and ReEDS estimate a decrease in total US generation. MUSE estimates a decrease as the energy system reacts more rapidly than the power sector and substitutes gas to electricity when gas prices are high, *vice versa* when gas prices are low. ReEDS 2.0 estimates nearly a net zero response under the *low* gas price shock scenario as US exports to Canada increase by nearly the same amount as the decrease in US exports to China.

The response of US electricity price by shock case and system configuration, presented in Fig. 9, roughly mimics the responses of Canadian prices. The LowRenCost scenario results in the least increase under the *high* gas price shock case whereas HighRenCost results in the greatest price increase. Although RenMandate results in less of a price increase than the BAU scenario, it also acts as a price floor given the inability to shift more into gas generation given the requirement to generate from renewable technologies.

Similar to Mexico, the impacts of the *high* gas price shock on US net exports (presented in Figure 22 in Appendix C) are consistent across models and system configurations. Both models estimate a reduction in US net exports (increased reliance on imports) under the *high* gas price shock case. Although EC-MSMR estimates an increase in net exports under the *low* gas price shock case, the results from ReEDS 2.0 are indiscernible from the reference cases. The majority of the increased imports under the *high* shock case are from Canada as it is not estimated to build out a significant amount of natural gas capacity, thus insulating it from the natural gas price shocks.

3.6. USA natural gas

The United States is the largest producer of natural gas in North

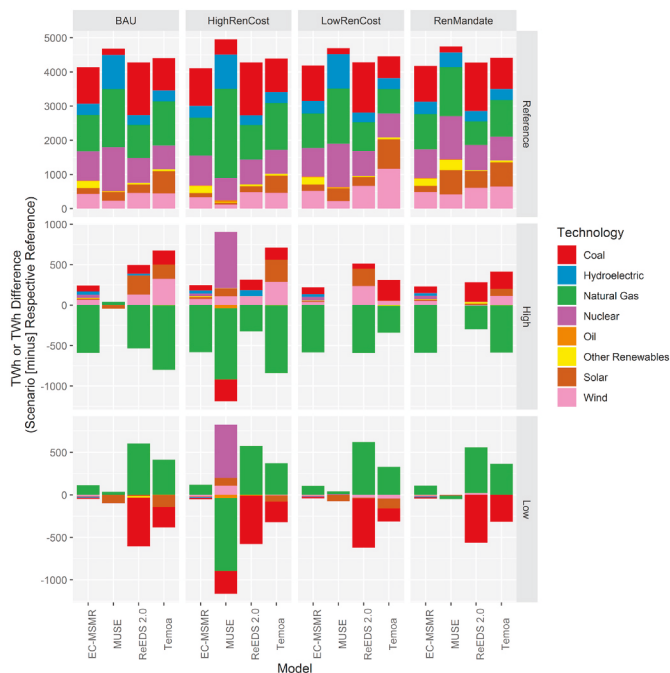


Fig. 8. 2030 US generation by technology and difference from respective reference case.

Table 5
Change in total 2030 US generation by shock case relative to respective reference scenario (TWh).

	BAU	HighRenCost	LowRenCost	RenMandate
High				
EC-MSMR	-345.9	-334.4	-364.4	-358.1
MUSE	-5.5	-283.4	0.0	0.0
ReEDS 2.0	-37.6	-8.0	-76.8	-16.4
Temoa	-125.9	-128.9	-30.8	-170.4
Low				
EC-MSMR	64.3	66.0	63.4	63.4
MUSE	-62.8	-338.5	-34.4	-49.7
ReEDS 2.0	-1.2	-5.1	-0.6	-4.6
Temoa	30.7	49.1	16.7	48.3

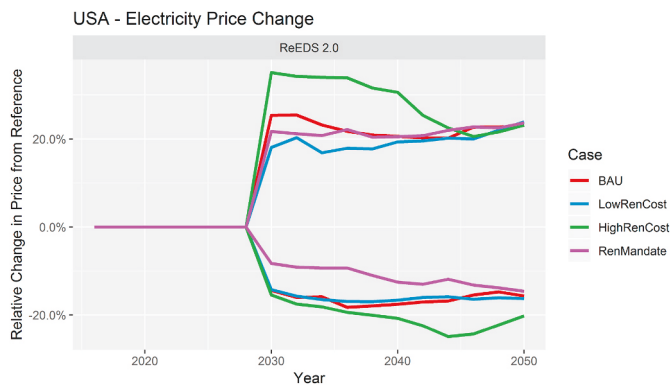


Fig. 9. Change in wholesale US electricity price relative to respective reference case.

America, and its central position drives the majority of supply across borders. As presented in Fig. 10, NANGAM's BAU case predicts the US to become a net exporter for the long run, which majority of the gas being exported to Mexico. Under the low natural gas price scenario, the United States is expected to increase its net exports even more, satisfying the resulting increase in demand. This impact is exacerbated in the long-run under the high renewable costs scenario, although a renewable mandate seems to stabilize exports closer to the BAU case because of its policy structure. High natural gas prices have more of an impact in the short term but end up being not as impactful on production and exports in the long run. Lower renewable costs make the impact even smaller in the long run, and a renewable mandate causes barely any difference in exports from the BAU, but production is still impacted as local demand changes.

4. Conclusions and policy implications

In this work, we've explored how the electricity and natural gas energy systems respond to unexpected and dramatic upward and downward shocks to natural gas prices. Results indicate that the responses vary drastically across countries studied and, in some cases, across models. There are several consistent findings across the models as well which we'll focus on here. Finally, the model structures lend explanation to the differences in results as this study features both bottom-up, engineering system representations as well as top-down, economy-wide models of different varieties.

A consistent conclusion across all countries is that the renewable mandate resulted in the least price decrease under the *low* shock cases yet also resulted in less of a price increase under the *high* shock cases

than the BAU system configuration. This implies that there is a benefit to enforcing the renewable mandate if there are upward forces on natural gas prices but the system is less able to take advantage of the lower prices available when natural gas prices decrease. Although the renewable mandate increases the diversity of the electricity generation portfolio, the policy design itself reduces the flexibility to respond to and take advantage of lower natural gas prices.

Across the three countries, there is a general consistency across models of which technologies are responding on the margin to the natural gas price shocks. Canada is typically responding with substituting between wind and, for some models, hydroelectric generation for gas generation. Mexico is responding to shocks by substituting between wind and solar generation for gas generation. Finally, the US typically responds by substituting coal, wind, and solar generation for gas generation. The magnitude of these responses depends on the system buildouts up to the point of the shock and can result in some unintended consequences. For example, in the US we saw that the renewable mandate case resulted in the resurgence of coal generation under the *high* shock cases but, in most other cases, coal's resurgence was limited.

In several instances, it is apparent that the differences in model structures and assumptions drive the differences in results. In cases where the top-down and bottom-up models generally agreed, an example being the changes in generation by technology, the differences in the bottom-up models are consistently greater than the top-down models. We speculate a number of reasons including substitutability assumptions and lacking grid operations details in top-down models; in contrast the static boundary conditions that define the capital, fuel, and labor availability and prices limit the intersectoral and economy-wide interaction in most bottom-up models. The models' perspectives help to interpret results as well. As an example, the Canadian natural gas results indicate agreement in direction between the two CGE models (NEB-EFMS and EC-MSMR) but contrast between them and NANGAM. Although speculative, we believe this to be from the model perspective of NANGAM which is producer-focused with game theoretical aspects as well as engineering-oriented production and transport constraints. Although markets reach equilibrium in CGE models assuming cost-minimizing (or profit-maximizing) producers, technologies' production functions do not typically include such constraints or cost representations.

This work elucidates the implicit tradeoff of increased, pre-shock renewable generation penetration under the *high* and *low* cases. Under the *high* shock cases, the LowRenCost scenario consistently resulted in the lowest price increases. However, under the *low* shock cases, the price reductions from the LowRenCost system configuration were either indiscernable from or less than the BAU system configuration. Therefore, a tradeoff exists between having the benefit of dampening upward price shocks versus not being able to take advantage of downward price shocks as the system was built with less gas capacity up to that point in time. In contrast, the HighRenCost scenario results in the greatest price increases and decreases under the *high* and *low* shock scenarios, respectively, for all countries. In several instances, the exposure and vulnerability to price shocks is primarily driven by the competitiveness of gas in the reference scenario; said differently, the system's buildout and subsequent reliance on natural gas dictates the magnitude of response when faced with a price shock.

The natural gas price shocks can have substantial influence over the international trade of electricity. Although inconsistent across models, Canada has drastic increases of net exports under the *high* shock cases as modeled by ReEDS 2.0, yet the more aggregated, economy-wide models do not predict such a substantial reaction for Canada and have a reversed relationship in response to the *high* shocks. Mexico is rather unimpacted by the *low* price shocks whereas it increases net imports several times over the reference case under the *high* price shocks. The increased imports from Canada dominate the exports to Mexico for the USA under the *high* shock case and it increases imported electricity under all system configurations. This highlights a broader concept that

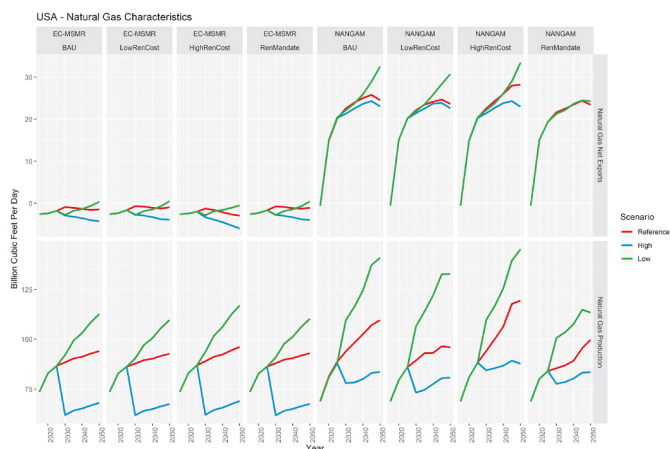


Fig. 10. US natural gas net exports and natural gas production.

the trade relationships are dependent on the system buildouts; since Mexico builds out its natural gas capacity alongside the USA, their trade relationship is relatively unaffected relative to Canada which has lesser natural gas electricity generation.

This study shows that some observed trends of natural gas markets in North America will continue under all scenarios but will be exacerbated under different shocks and renewable policies and costs. The United States remains the largest exporter, and Mexico a net importer. However, natural gas behaves as a complement to renewable energy in the short run, and a substitute in the long run, which is exacerbated/mitigated by higher/lower renewable costs. Policy design is thus critical for how natural gas markets respond to shocks. Net exports change minimally under the renewable mandate scenario, indicating that the policy will have minimal impact on cross-border trade. However, higher or lower renewable costs impact the market quite a bit, implying that shocks to natural gas prices need to be coupled with an understanding of renewables costs in order to have a comprehensive understanding of what is happening in the market.

Limitations to this study lead to the potential for future research. For one, we chose only two characteristics to harmonize (gas prices and renewable technology costs). For a more coordinated comparison, several aspects of these models could be further harmonized including demand projections, temporal representations, all cost assumptions, and policy representations. Although we offer comments for a very surface-level comparison of models, a continuation of this study would focus on how model assumptions drive the responses to price shocks. Second, this study has only focused on one specific type of shock whereas future work could look at the combinations of fuel price shocks with policy shocks, macroeconomic shocks, and technological breakthroughs. Finally, this work would benefit from a wholistic metric of the impact of shocks; for example, [Uria-Martinez et al. \(2018\)](#) compare the welfare responses of different system configurations and shocks but resource limitations constrained this study from mimicking that approach. Although general resilience has become a focal point of power systems research, very few researchers have looked at economic resilience in the same way as this study - yet it offers a unique perspective for system planners and policy makers.

Matthew Hansen acknowledges and thanks Melanie Stogran for natural gas production modeling, and Ryan Safton and Michael Nadew for modeling assistance.

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Policy. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

Research support for C. Avraam and S. Siddiqui was funded in part by NSF Grant #1745375 [EAGER: SSDIM: Generating Synthetic Data on Interdependent Food, Energy, and Transportation Networks via Stochastic, Bi-level Optimization].

CRediT authorship contribution statement

Maxwell Brown: Conceptualization, Investigation, Visualization, Writing. **Sauleh Siddiqui:** Conceptualization, Methodology, Writing - original draft. **Charalampos Avraam:** Methodology. **John Bistline:** Methodology. **Joseph Decarolis:** Methodology. **Hadi Eshraghi:** Methodology. **Sara Giarola:** Methodology. **Matthew Hansen:** Methodology. **Peter Johnston:** Methodology. **Saroj Khanal:** Methodology. **Anahi Molar-Cruz:** Methodology.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.enpol.2020.112046>.

References

- Bosch, J., Staffell, I., Hawkes, A.D., 2017. Temporally-explicit and spatially-resolved global onshore wind energy potentials. *Energy* 131, 207–217. <https://doi.org/10.1016/j.energy.2017.05.052>.
- Brown, M., et al., 2020. Regional Energy Deployment System (ReEDS) Model Documentation: Version 2019. National Renewable Energy Lab.(NREL), Golden, CO (United States). <https://www.nrel.gov/docs/fy20osti/74111.pdf>.
- Coen, R.M., Hickman, B.G., 1983. Energy shocks and macroeconomic activity: simulation results from the Hickman-Coen model.
- Crow, D.J.G., Giarola, S., Hawkes, A.D., 2018. A dynamic model of global natural gas supply. *Appl. Energy* 218, 452–469. <https://doi.org/10.1016/j.apenergy.2018.02.182>.
- DeCarolis, J., Hunter, K., Sreepathi, S., 2018. Temoa Project Documentation (P. 57).
- EIA, 2016. Annual Energy Outlook 2017 with Projections to 2050, p. 64.
- EIA, 2017. Canada is the United States' largest partner for energy trade [U.S. Energy Information Administration (EIA)]. Retrieved July 25, 2019, from Today in Energy website: <https://www.eia.gov/todayinenergy/detail.php?id=30152>.
- EIA, 2019. Natural Gas Imports and Exports. Retrieved August 27, 2019, from Energy Explained website: <https://www.eia.gov/energyexplained/index.php?page=naturalgasimports>.
- EIA, 2019a. June 28). U.S. Natural Gas Consumption by End Use. Retrieved July 25, 2019, from Natural Gas website: https://www.eia.gov/dnav/ng/ng_cons_sum_dc_u_s_a.htm.
- EIA, 2019b. June 28). U.S. Natural Gas Pipeline Exports to Mexico. Retrieved July 25, 2019, from Natural Gas website: <https://www.eia.gov/dnav/ng/hist/n9132mx2A.htm>.
- Feijoo, F., Huppmann, D., Sakiyama, L., Siddiqui, S., 2016. North American natural gas model: impact of cross-border trade with Mexico. *Energy* 112, 1084–1095. <https://doi.org/10.1016/j.energy.2016.06.133>.
- Feijoo, F., Iyer, G.C., Avraam, C., Siddiqui, S.A., Clarke, L.E., Sankaranarayanan, S., et al., 2018. The future of natural gas infrastructure development in the United States. *Appl. Energy* 228, 149–166. <https://doi.org/10.1016/j.apenergy.2018.06.037>.
- Ghosh, M., Luo, D., Siddiqui, M.S., Zhu, Y., 2012. Border tax adjustments in the climate policy context: CO2 versus broad-based GHG emission targeting. *Energy Econ.* 34, S154–S167.
- Giarola, S., Crow, D.J.C., Hawkes, A., 2019. June 3). *Simulating The Carbon Price Trajectory in Energy Systems with Imperfect Foresight*. Presented at the 38th International Energy Workshop, Paris, France.
- Hunter, K., Sreepathi, S., DeCarolis, J.F., 2013. Modeling for insight using tools for energy model optimization and analysis (Temoa). *Energy Econ.* 40, 339–349.
- Huntington, H.G., 2005. The economic consequences of higher crude oil prices, 9. *Energy Modeling Special Report*.
- Huppmann, D., Egging, R., 2014. Market power, fuel substitution and infrastructure—A large-scale equilibrium model of global energy markets. *Energy* 75, 483–500.
- Jones, D.W., Leiby, P.N., Paik, I.K., 2004. Oil price shocks and the macroeconomy: what has been learned since 1996. *Energy J.* 25 (2), 1–32 (Retrieved from JSTOR).
- Kilian, L., 2009. Not all oil price shocks are alike: disentangling demand and supply shocks in the crude oil market. *Am. Econ. Rev.* 99 (3), 1053–1069.
- Kilian, L., 2010. Oil price volatility: origins and effects. *WTO Staff Working Paper*.
- Kilian, L., 2014. Oil price shocks: causes and consequences. *Annu. Rev. Resour. Econ.* 6 (1), 133–154.
- Lescaroux, F., Mignon, V., 2008. On the influence of oil prices on economic activity and other macroeconomic and financial variables. *OPEC Energy Review* 32 (4), 343–380. <https://doi.org/10.1111/j.1753-0237.2009.00157.x>.
- Molar Cruz, A., Guillén, B., Hamacher, T., 2018. Cost-optimal regional deployment of renewable energy in the Mexican electric power system. *International Energy Workshop*, 2018. Presented at the Gothenburg, Sweden. Retrieved from: http://iew2018.org/wp-content/uploads/2018/07/4F_Molar-Cruz.pdf.
- National Energy Board, 2016. Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040. Retrieved from: <https://www.neb-one.gc.ca/nrg/ntgrtd/fttr/2016/2016xctvsmmr-eng.pdf>.
- North American Cooperation on Energy Information (NACEI), 2019. Retrieved. <https://www.nacei.org/#/!/overview>. (Accessed 25 July 2019).
- Oladosu, G.A., Leiby, P.N., Bowman, D.C., Uriá-Martínez, R., Johnson, M.M., 2018. Impacts of oil price shocks on the United States economy: a meta-analysis of the oil price elasticity of GDP for net oil-importing economies. *Energy Pol.* 115, 523–544.
- Park, J., Ratti, R.A., 2008. Oil price shocks and stock markets in the U.S. and 13 European countries. *Energy Econ.* 30 (5), 2587–2608. <https://doi.org/10.1016/j.eneco.2008.04.003>.

- Patankar, N., Eshraghi, H., Nagarajan, S., DeCarolis, J.F., 2019. Documentation of the US 9-Region Temoa Energy System Database. (Draft Available upon Request).
- Sachs, J., Meng, Y., Giarola, S., Hawkes, A., 2019. An agent-based model for energy investment decisions in the residential sector. *Energy* 172, 752–768. <https://doi.org/10.1016/j.energy.2019.01.161>.
- Sankaranarayanan, S., Feijoo, F., Siddiqui, S., 2018. Sensitivity and covariance in stochastic complementarity problems with an application to North American natural gas markets. *Eur. J. Oper. Res.* 268 (1), 25–36. <https://doi.org/10.1016/j.ejor.2017.11.003>.
- SENER, 2016. Natural Gas Outlook 2016–2030. Retrieved from. https://www.gob.mx/cms/uploads/attachment/file/236863/NG_Outlook_2016-2030_P.compressed.pdf.
- Stern, D.I., 1993. Energy and economic growth in the USA: a multivariate approach. *Energy Econ.* 15 (2), 137–150. [https://doi.org/10.1016/0140-9883\(93\)90033-N](https://doi.org/10.1016/0140-9883(93)90033-N).
- Uriá-Martínez, R., Leiby, P.N., Brown, M.L., 2018. Cost of oil and biomass supply shocks under different biofuel supply chain configurations. *Transport. Res. Rec.* 2672 (24), 31–40.
- Vimmerstedt, L.J., Augustine, C.R., Beiter, P.C., Cole, W.J., Feldman, D.J., Kurup, P., et al., 2018. 2018 Annual Technology Baseline (ATB). National Renewable Energy Lab.(NREL), Golden, CO (United States).
- Zhu, Y., Ghosh, M., Luo, D., Macaluso, N., Rattray, J., 2018. Revenue recycling and cost effective GHG abatement: an exploratory analysis using a global multi-sector multi-region CGE model. *Climate Change Economics* 9 (1), 1840009.