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North American natural gas market and infrastructure developments under different mechanisms of renewable policy coordination

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ABSTRACT

Renewable Portfolio Standards (RPS) accelerate renewables deployment but their impact on fuel-fired plants remains ambiguous. North American natural gas consumption has been growing due to its decreasing cost in North America, policy initiatives, and its relatively low CO_2 emissions rate compared to coal. In this paper, we study the implications for the natural gas sector of more stringent RPS under different coordination schemes in an integrated North American natural gas market. The scenarios assume that Renewable Energy Certificates generated in each region are traded 1) among all countries, 2) only within each country, and 3) only within model regions. We implement the three policies in four different energy and electricity models to generate projections of future natural gas consumption. Subsequently, we feed regional or country-level consumption changes of each model in each scenario to the North American Natural Gas Model. We find that lower RPS coordination among regions results in increased U.S. natural gas exports to Canada, increased U.S. natural gas prices, and decreased net U.S. natural gas exports to Mexico in the long term. Moreover, international coordination of RPS in the electricity sector leads to smaller price discrepancies in the U.S. natural gas market when compared to the reference scenario.

1. Introduction

Establishing Renewable Portfolio Standards (RPS) requires renewable technologies to cover a minimum share of retail electricity consumption. Renewable electricity producers — such as wind, solar, or geothermal — generate minimal emissions. Although the capital cost of renewables is high compared to that of fuel generators, its decrease has been a key driver of the growing investment on renewable energy in North America (EIA, 2020). RPS aim to accelerate the introduction and adoption of non-emitting technologies in the power producing sector. RPS are enforced either at the national, provincial, or regional level and in most states introduce a market for Renewable Energy Certificates (RECs). RECs are financial products that are traded independently of the physical power market. RECs are created when a renewable energy source produces a benchmark amount of energy. Hence, RECs result in additional revenues for renewables. At the same time, emitting technologies need to purchase RECs in order to meet the RPS goal. Therefore, RPS result in emitting technologies subsidizing non-emitting technologies and thus favor the latter over the former (Yin and Powers, 2010).

The idea of RPS was first introduced by Rader and Norgaad (1996). Wiser et al. (2007), point out that although the idea was developed by Rader and Norgaad (1996), RPS were already in place in Minnesota and Iowa. These policies were not referred to as RPS until the late '90s. By 2018, more than 29 U.S. states and the District of Columbia had adopted some variation of RPS (EIA, Updated renewable portfolio standards will lead to more renewable electricity generation., 2019). Moreover, Europe has a similar scheme not just for the electricity sector, but for energy consumption overall. The Renewable Energy Standards (RES) set individual targets for member countries on the percentage of gross energy demand, not just electricity, covered by renewable energy sources

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(European Parliament and European Council, 2009). RES are set centrally from the European Commission, but vary among countries on the basis of their potential to exploit renewable energy resources.

As a result of RPS, production from fossil fuel-fired plants is being discouraged. However, in the case of natural gas, RPS do not necessarily translate into a decrease of production from natural gas-fired plants. Under RPS, gas-fired plants – as any other CO_2 emitting technology – are disadvantaged compared to non-emitting technologies. At the same time, RPS are often coupled with emissions cap or emissions tax policies at the state or federal level. Natural gas-fired plants have benefitted from such schemes in the short term due to their relatively lower emissions factors compared to other fossil fuel-fired plants. In addition, natural gas in North America is becoming cheaper (Feijoo et al., 2016). Thus, the combination of RPS, emissions policies, and resource availability in North America has led to an overall increase in natural gas consumption by the electricity sector.

More generally, natural gas is an important source of energy for the residential, commercial, industrial, electricity, and transportation sectors. Shocks in these sectors result in different natural gas infrastructure investment decisions, which in turn affect long-term natural gas prices. The resulting price deviations can be mitigated by developments in the natural gas market. Under integrated natural gas markets, prices between trade partners are more tightly linked, thus more resilient to shocks. Huntington (2009) argues that enhanced integration of the North American natural gas markets leads to more stable long-term natural gas prices and increases energy security of the U.S., Canada, and Mexico. However, the interdependence of electricity and natural gas markets renders the latter vulnerable to changes in the former, regardless of the level of integration of natural gas infrastructure. Moreover, different energy and electricity models are often built using different databases or with different level of detail. Consequently, the models still disagree about the resulting impact of the same policy to the electric and natural gas sectors.

In this paper we focus on the interplay between RPS and natural gas markets and infrastructure. To do so, we couple four models that provide estimates of natural gas consumption with the North American Natural Gas Model (NANGAM) to simulate the natural gas system in North America. Moreover, this analysis aims to complement the analysis in Avraam et al, (2020), and Bistline et al. (2020) conducted within the scope of the Energy Modeling Forum 34 (Huntington et al., 2020). Avraam et al, (2020) focus on the response of North American natural gas markets under different assumptions on key drivers of natural gas production. On the other hand, this paper aims to quantify the impact of RPS, as studied in Bistline et al. (2020), on the natural gas system due to the interdependence of the electricity and natural gas sectors. More specifically, we ask:

- What are the implications of different levels of RPS coordination for regional natural gas production and pipeline infrastructure in North America?
- Under the same level of RPS coordination, how sensitive are the results for the natural gas sector to the modeling assumptions regarding mandated renewable shares?
- How do the developments in the natural gas market inform policy-making in the electricity sector?

2. Literature review

RPS are policy tools for reducing CO_2 emissions that explicitly favor renewables, as opposed to technology-neutral policies that do not differentiate between power generation technologies. Young and Bistline (2018) find that the cost of RPS, as measured by the Net Present Value (NPV) through 2050, can be twice that of a technology-neutral portfolio for the same CO_2 emissions target. Upton and Snyder (2017) conclude by using empirical methods that RPS increase electricity prices between 10.9% and 11.4%. Moreover, Palmer and Burtraw (2005) argue that for the same emissions reduction target, a cap-and-trade system is more cost-efficient when compared with RPS, as it forces a greater quantity of coal-fired plants, the highest emitters, out of the system. Their findings are consistent with Fischer and Newell (2008) who identify that a market for CO_2 emissions permits is the most cost-effective policy among six policy alternatives. Weyant (2008) and Schmalensee and Stavins (2017) identify how political concerns can bias the design of emissions reduction policies.

Lack of coordination of climate policies between regions in the electricity sector can lead to increased electricity prices and greater CO_2 emissions. Bistline and Rose (2018) find that in the absence of coordination in the power sector it is more likely for economic activity to shift from more regulated regions to less regulated regions, leading to increased CO_2 emissions and electricity prices. Fullerton and Karney (2018) highlight the importance of coordinating policies that target different pollutants at different sectors of the economy at the same time. Furthermore, Bistline et al., (2019) conclude that in the absence of RECs, coordinated policies in integrated power markets can decrease the NPV of a RPS scheme in the U.S. by 148 billion dollars. In the presence of RECs, the cost of RPS decreases by 67 billion dollars. Yin and Powers (2010) focus on the treatment of RECs when states set individual renewable energy targets. They find that when states are allowed to trade RECs, then some states may fail to meet their individual emissions targets. In addition, Bowen and Lacombe (2017) argue that there exists strong evidence that states with stringent RPS legislation drive investment in renewables higher in neighboring states with less strict RPS laws.

The majority of the studies that include the natural gas sector when analyzing RPS focus on the impact of natural gas prices on the effectiveness of RPS and vice versa. Shearer et al. (2014) find that under a moderate carbon tax and a strict carbon cap, the availability of cheap natural gas delays the introduction of renewables by a decade. However, under RPS, the introduction of renewables follows the same trajectory for both scarce and abundant natural gas resources. Bistline and Young (2019) study the penetration of wind and solar in the U.S. power generation mix for natural gas prices of 4$, 6$, and 8$ per MMBtu in the presence of RPS. They find that moving from 4$ to 8$ per MMBtu can increase the share of solar and wind by 33%, given transmission expansion costs and CO_2 policies as in their Reference scenario. Moreover, RPS have been considered in all the Annual Energy Outlooks published by the U.S. Energy Information Administration (EIA) since 1998 (EIA, 1998). In two separate studies by EIA the implementation of a 10% RPS for the U.S. decreases natural gas wellhead prices by 3.67% and 0% respectively (EIA, Impacts of a 10-percent renewable portfolio standard (SR/OIAF/2002–03), 2002), (EIA, Impacts of a 10-percent renewable portfolio standard (SR/OIAF/2003–01), 2003). Wiser et al. (2007) collect results of 12 studies published between 1998 and 2003 by EIA, the American Council for an Energy-Efficient Economy (ACEEE), the Tellus Institute, and the Union of Concerned Scientists. The studies quantify the reduction of natural gas wellhead prices due to the introduction of RPS targets of 6.3% in Rhode Island, and 10%, 15%, or 20% in the U.S. (Wiser & Bolinger, Can deployment of renewable energy put downward pressure on natural gas prices? 2007)

Studying the impact to one sector of a policy applied to another sector requires understanding the interdependencies between two different sectors. Hence, modelers need to develop tools with the appropriate level of detail in both sectors or link existing bottom-up models. Modelers can choose between a soft-link or a hard-link approach. To the extent that one model's output is used as another model's input, in a soft-link the first model does not account for the response of the agents in the second model. This means that a soft-link, albeit solving faster than a hard-link, rarely converges to a point that solves both models (Krook-Riekkola et al., 2017). On the other hand, different models are calibrated using different databases that are often inconsistent for the data at the interdependencies, which is critical for the implementation of a hard-link. Moreover, solving two fully integrated large-scale bottom-up models can prove an arduous task computationally (Bohringer and Rutherford, 2009). Therefore, the choice of model-coupling method depends both on the models at hand and the research question (Hourcade et al., 2006). Both the soft-link (Hogan and Weyant, 1982; Feijoo et al., 2018) and the hard-link approaches (Tapia-Ahumada et al., 2015) have been used in energy and climate studies. Among the hard-link approaches, Abrell and Weigt (2012) introduce a framework for integrating partial equilibrium models of the electricity and natural gas sectors. The framework is similar to co-optimization (He et al., 2018b) and its variations, namely robust co-optimization (He et al., 2018a) and security-constrained co-optimization (Zhang et al., 2015). Natural gas models have also been integrated with optimal power flow models (Martines-Mares and Fuerte-Esquivel, 2012).

To the best of the authors' knowledge, little to no emphasis has been given to the impact of RPS on regional natural gas markets. This paper aims to understand the interplay between RPS and the natural gas market and quantify the regional impact of RPS schemes to natural gas infrastructure. Moreover, it aims to understand how policies in the electricity sector affect the natural gas sector and subsequently influence natural gas trade between the U.S., Canada, and Mexico.

3. Objectives and scenarios

Our objective is to quantify the impact of RPS on the natural gas market. RPS mechanisms result in higher penetration of renewables[1] in the electricity sector. In our formulation, the U.S., Mexico, and Canada[2] mandate that the share of renewables in the power generation mix is greater than or equal to 30% in 2020, 40% in 2030, 50% in 2040, and 60% in 2050, with linear increase between years. These targets are fed into the individual electricity or macroeconomic models that output natural gas consumption. The resulting change in natural gas consumption is then fed into NANGAM to quantify the impact of each policy on natural gas markets and infrastructure. We simulate three different variations that assume different levels of RPS coordination between the U.S., Canada, and Mexico.

a) **International coordination (Scenario 1):** The U.S., Canada, and Mexico are obliged to jointly meet the scenario's renewables penetration targets. International coordination allows for unbundled RECs to be traded between all three countries.
b) **No international coordination (Scenario 2):** Each country is obliged to meet the scenario's renewables penetration targets individually. Lack of coordination implies that unbundled RECs can be traded only among electricity producers of the same country.
c) **No inter-regional coordination (Scenario 3):** Each region within each country is obliged to meet the scenario's renewables penetration targets individually. Lack of coordination implies that unbundled RECs can be traded only between electricity producers of the same region.

The impact of different RPS coordination schemes on natural gas consumption is not trivial and is analyzed in detail in Bistline et al. (2020). Bistline et al. (2020) show that limiting RPS coordination leads to more gas generation being displaced in the U.S. This finding builds on existing literature that suggests that RPS increase the displacement of natural gas in the electricity sector (Mai et al., 2018). Moreover, in Scenario 1, regions with little solar and wind potential are able to leverage the potential of their neighbors in order to meet the renewables penetration target. Subsequently, the required renewables capacity needed in North America on aggregate to meet that target is minimized, which in turn allows for more natural gas capacity to be installed. Although natural gas-fired plants are displaced compared to Reference in all three scenarios, greater RPS coordination among regions results in less installed renewable capacity which leaves more room for investment in natural gas-fired plants. This is particularly the case with Canada that has an already high penetration of hydro. In Scenario 1, Northeastern U.S. leverages the hydro and wind potential of Canada instead of investing in their lower quality renewable resources. On the other hand, in Scenario 3, the same regions would have to invest in their inferior resources to meet their targets. Consequently, a larger part of Northeastern U.S. demand would be covered from renewables in the future, leaving less room for investment in natural gas-fired plants. A more in-depth discussion on the conditions under which this argument suffices to explain the results for gas-fired plants, as well as detailed results for the electricity sector can be found in Bistline et al. (2020).

4. Methods

For the purpose of this study, four models were used to project natural gas consumption for the three variations of RPS policies. Moreover, other than the renewables penetration targets, no other features of the models used to provide natural gas consumption projections were altered, including the assumptions on investment and operational costs. First, we provide an overview of the models used in this study.

NANGAM (Feijoo et al., 2016) is a game-theoretic, planning model that simulates production, consumption, and trade decisions for natural gas in the U.S., Canada, and Mexico. NANGAM comprises 17 regions, including the nine census regions for the U.S., a node for Alaska and Hawaii, five regions for Mexico (Northwest, Northeast, Interior-West, Interior, and South-Southeast), and two regions for Canada (East and West). Representative producers exist in the 13 regions that have natural gas production capacity and regional consumption is approximated using a linear inverse demand curve. Pipeline interconnections between regions are aggregated into 69 arcs, whose investment, fixed, and marginal cost of transporting natural gas is based on a database of 778 existing projects and 187 new ones. In NANGAM every region in the U.S. and Canada is also equipped with a storage facility. At the upstream level, producers compete in a Nash-Cournot style market wherein pipeline operators are assumed to be profit maximizers who ensure that regional natural gas demand is met. Investment decisions on production and pipeline capacity are endogenous and are based on future profitability. NANGAM considers three seasons – peak, high, and low – and runs in five-year time steps up to the year 2050. NANGAM is based on Multimod (Huppman and Egging, 2014) and therefore can simulate supply-side or demand-side shocks, infrastructure development decisions, and policy interventions.

ReEDS2.0 (Eurek et al., 2016) simulates operation and capacity expansion decisions for the electricity markets of the contiguous U.S., Canada, and Mexico. It comprises 205 Balancing Areas and 454 Resource Supply regions. ReEDS2.0 runs in two-year time steps from 2010 to 2100. Each year is divided into four seasons in which each season is further divided into four time segments that represent overnight, morning, afternoon, and evening. ReEDS2.0 is a linear program and is suitable for modeling emissions policies such as carbon taxes and emissions caps.

NATEM (Vaillancourt et al., 2018) is based on MARKAL/TIMES, from which it inherits the detailed representation of the entire energy system. As with TIMES, the decisions in NATEM are the result of an intertemporal cost minimization program. NATEM-Canada includes all 13 Canadian provinces and territories. There exist five end-use consumer categories (commercial, residential, industrial, transportation,

[1] Following Bistline et al. (2020), the renewable technologies considered are wind, biomass, concentrated solar power (CSP), utility-scale photovoltaic (PV), geothermal, and hydro.

[2] Canadian hydropower generation constitutes more than 60% of the energy mix in 2016. Therefore, new renewables would be introduced due to RPS in order for neighboring regions to meet a certain requirement and only to the extent that they are rendered competitive compared to renewables of other regions.

Table 1
Models and scenarios overview.

Model Name	Abbr.	Sectors	Countries	Regions	Scenarios	Supporting Organization(s)
North American Natural Gas Model	NANGAM	Natural Gas	U.S., Canada, Mexico	17	S1, S2, S3	Johns Hopkins University
Regional Energy Deployment System	ReEDS2.0	Electricity	U.S., Canada, Mexico	73	S1, S2, S3	National Renewable Energy Laboratory
North American TIMES Energy Model	NATEM	Electricity	Canada	13	S2, S3	ESMIA Consultants Inc.
National Energy Modeling System	NEMS-AEO2019	Electricity, End-Use	U.S.	22	S2, S3	U.S. Energy Information Administration
Global Energy System Model	GENeSYS-MOD	Electricity	Mexico	9	S2, S3	DIW Berlin

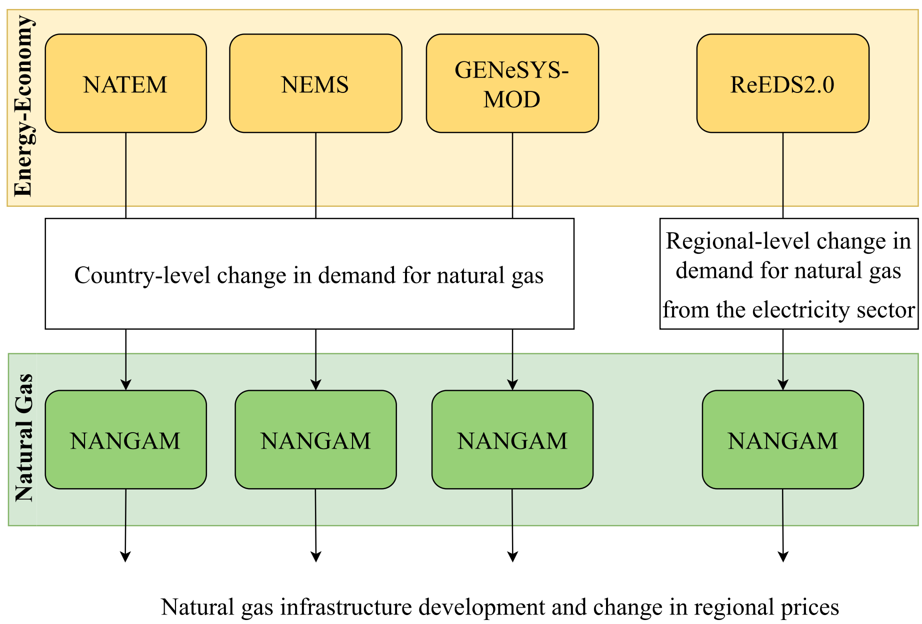

Fig. 1. Description of linkage between NANGAM and all other models.

and agriculture) each of which bases its decision on 70 end-use services. The version of NATEM used in this study is intertemporal and produces results in five-year time steps from 2015 to 2050. Each period accounts for four seasons that are further disaggregated into four intra-day periods per season.

NEMS-AEO2019 (EIA, NEMS - National Energy Modeling System: An Overview - EIA, 2009) is a bottom-up model of the U.S. energy system that is maintained by the U.S. Energy Information Administration. NEMS-AEO2019 comprises 16 sub-modules, each with its own technological features as well as regional disaggregation that is based on data availability and practicality for policy analysis. NEMS-AEO2019 yields projections in yearly time steps up to 2050. NEMS-AEO2019 is the version of NEMS used to produce the “Annual Energy Outlook 2019”. Compared to previous versions, it includes up-to-date data on taxes, vehicle stock, and updated assumptions for residential and commercial end-use technology, state-specific RPS and the solar Investment Tax Credit.

GENeSYS-MOD (Loffler et al., 2017) is based on the OSeMOSYS model (Open-Source Energy Modeling System) and extends the previous framework in many ways, namely by including a detailed power system, increasing the number of time segments, adding storage technologies, and improving the representation of trade. GENeSYS-MOD is a linear program that minimizes the sum of all the cost components of the energy system subject to constraints that simulate the workings of the energy system. The version used in this study divides Mexico into nine regions and includes all main generation technologies, namely utility PV, onshore and offshore wind, geothermal, coal-fired thermal plants and CHP, gas-fired thermal plants and CHP, and oil-fired thermal plants and CHP. Energy demand is disaggregated into demand from the electricity, the transportation, and the industrial heating sectors.

The four models that provide estimates of changes in natural gas consumption have different regional and temporal disaggregation. ReEDS2.0 models the electricity markets of the U.S., Canada, and Mexico in detail; NATEM models the energy system of Canada; NEMS-AEO2019 the energy system of the U.S.; and GENeSYS-MOD that of Mexico. Inputs for Scenario 1, which assumes coordination at the international level, were retrieved only from ReEDS2.0 since it includes all three North American countries. All models other than ReEDS2.0 provide percentage changes in country-level total yearly natural gas consumption for the country-specific Scenarios 2 and 3. The country-level percentage change is then applied to every NANGAM region included in each country. ReEDS2.0 has a more granular representation of North America than NANGAM. For that, ReEDS2.0 yearly output is aggregated to provide percentage changes in natural gas consumption by the electricity sector for every NANGAM region. The change in total natural gas consumption given ReEDS2.0 inputs is derived by the contribution of consumption from the electricity sector in total consumption of natural gas of a region. The derived region-specific change in total natural gas demand is then input into NANGAM for all time periods modeled in NANGAM (2015–2050). Table 1 provides an overview of each model's geographical scope and the scenarios each simulates.

The coupling method is a two-step process, as shown in Fig. 1. In the first step, all models with the exception of NANGAM project natural gas demand. Percentage changes in total natural gas consumption derived by the data provided by each model in each scenario are detailed in Appendix A. The results of each model are compared with respect to their own Reference scenario to compute percentage changes in natural gas consumption in each scenario. Subsequently, we decrease the linear term of the inverse demand curve of regional consumption of NANGAM (parameter int^{D}_{yhnd} (Feijoo et al., 2016)) by the amount provided from

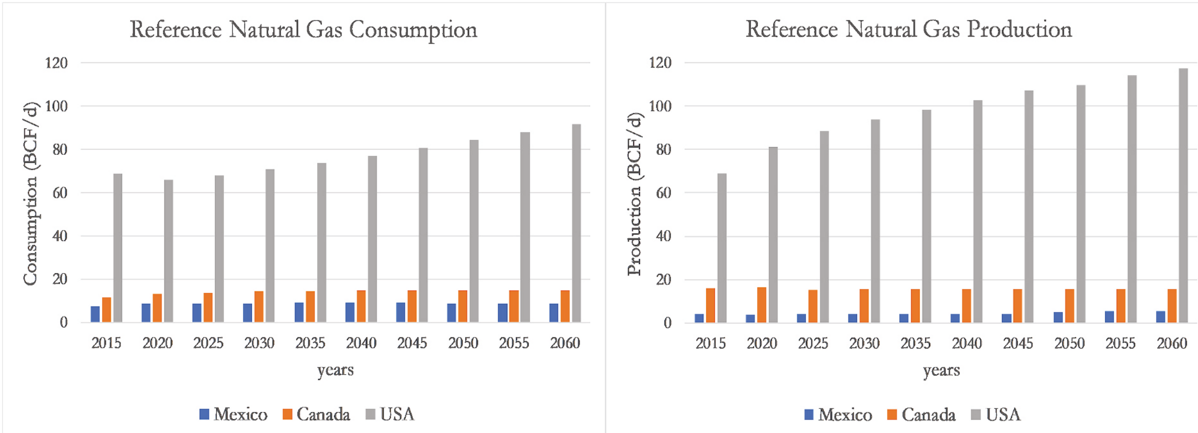

Fig. 2. Natural gas consumption (left) and production (right) in the Reference scenario for the U.S., Canada, and Mexico.

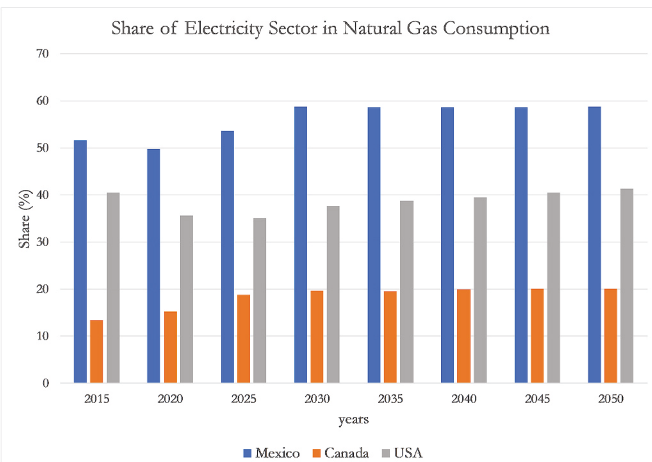

Fig. 3. Share (%) of consumption of electricity sector with respect to total natural gas consumption in the U.S., Canada, and Mexico.

each model. We run NANGAM for the new levels of demand to produce the final results.

Due to the scale of the study, we implement a soft-link between NANGAM and the other four models, where NANGAM receives as inputs percentage changes in total natural gas consumption. Had we implemented a hard-link between NANGAM and the individual models, we would have to adjust the calibration of NANGAM to each energy model, which would render the results non-comparable. Moreover, feeding NANGAM with percentage changes allows us to compare NANGAM results when using inputs from different models, each with different reference calibration, in an equal manner.

4.1. Reference scenario

We calibrate NANGAM in order to match production and consumption projections retrieved from AEO2017 (EIA, Annual energy outlook 2017 with projections to 2050., 2017) for the U.S., "Canada's Energy Future 2017" for Canada (NEB, 2017), and the "Natural Gas Outlook 2016–2030" published by the Mexican Secretary of Energy (Secretaría de Energía) SENER for Mexico (SENER, 2016). We retrieve reference estimates of regional production costs (EIA, Open Data, 2019), and pipeline operating and fixed costs (EIA, U.S. state-to-state capacity, 2019) from the U.S. Energy Information Administration. The calibration process entails adjusting the reference production and transportation costs in order to ensure that regional production, consumption and inter-regional trade in the Reference scenario are consistent with our reference data. Fig. 2 depicts reference natural gas production and consumption in the three countries. Fig. 3 highlights the tight connection between the electricity and natural gas sectors in the three countries. The electricity sector constitutes more than 50% of total demand for natural gas in Mexico and nearly 40% of total demand for natural gas in the U.S. intertemporal.

5. Results

5.1. Coordination at the country or regional level (Scenarios 2 and 3)

As mentioned in the Methods section, the four models used to produce estimates of natural gas consumption have different geographical

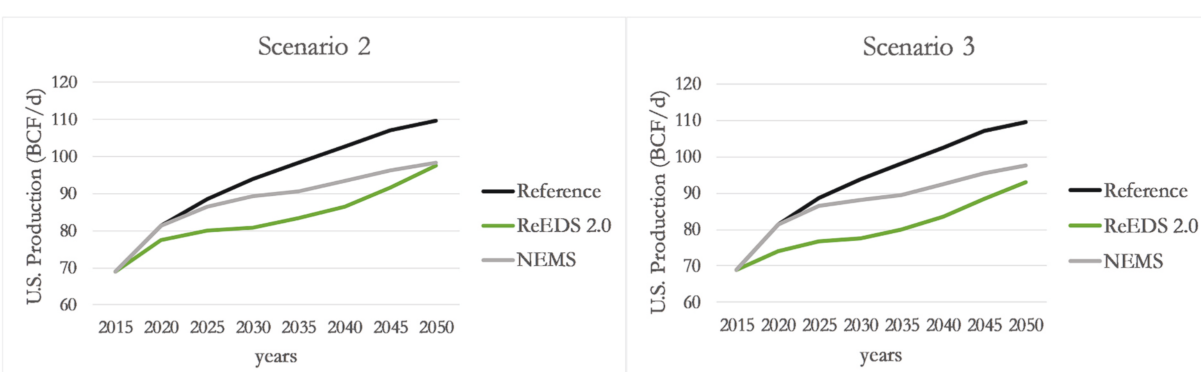

Fig. 4. NANGAM results. U.S. natural gas production in Scenarios 2 (left) and 3 (right) for inputs from different models.

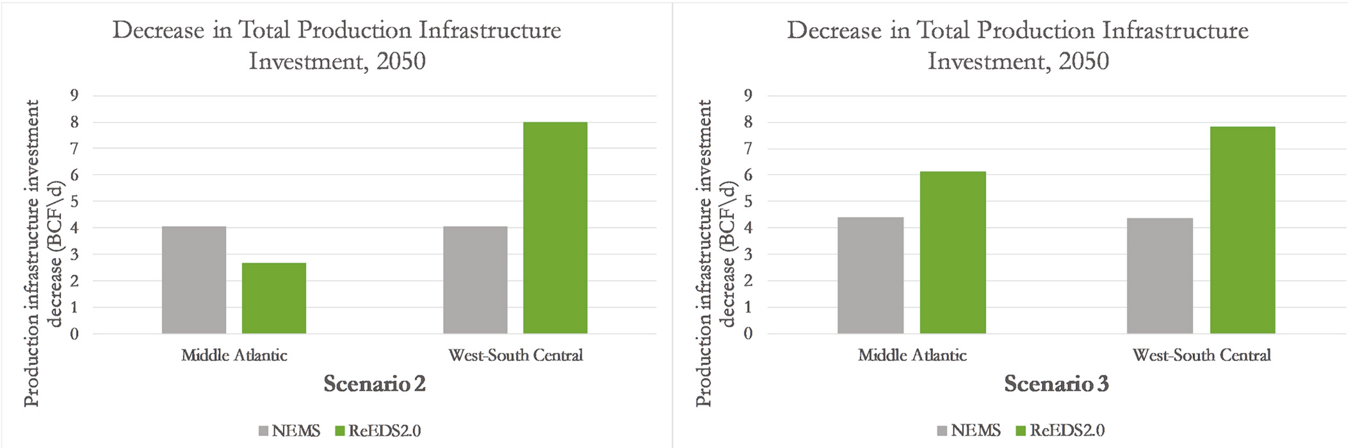

Fig. 5. NANGAM results. Decrease in regional U.S. natural gas production infrastructure investment by 2050 in Scenarios 2 (left) and 3 (right), compared to the reference scenario, for inputs from different models.

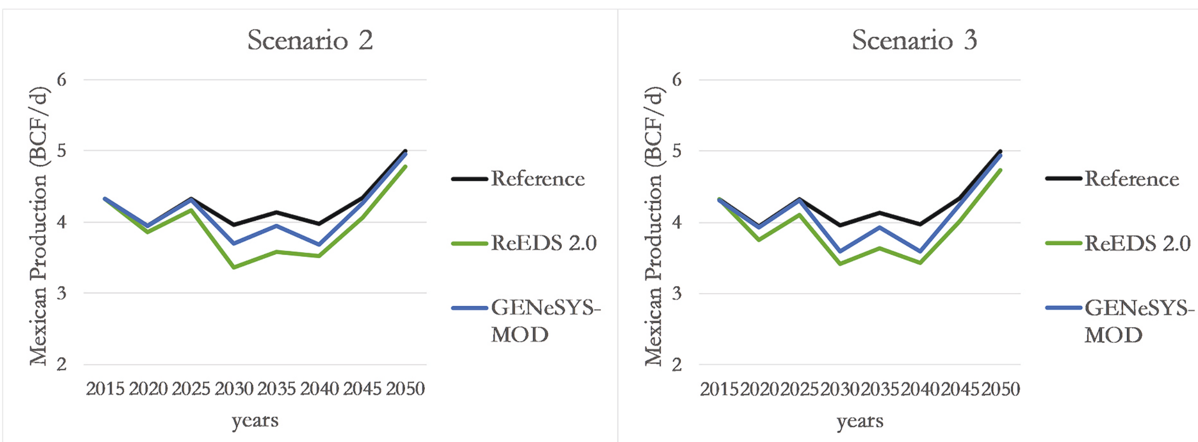

Fig. 6. NANGAM results. Mexican natural gas production in Scenarios 2 (left) and 3 (right) for inputs from different models.

scopes. In this section we compare how results change for each scenario based on inputs from different models. In order to be consistent, we compare country-level results using inputs only from models whose geographical scope includes that particular country. Apart from ReEDS2.0, all other models simulate the energy system of a single country. For that, they are not able to provide inputs for Scenario 1 which requires joint treatment of all 3 countries.

Fig. 4 illustrates how natural gas production in the U.S. changes based on inputs from NEMS-AEO2019 and ReEDS2.0. In Scenario 2, U.S. long-term natural gas production decreases by 11% for both ReEDS2.0 and NEMS-AEO2019 inputs. U.S. natural gas production becomes 100 BCF/d by 2050. When using inputs from NEMS-AEO2019 production starts decreasing later in the time horizon but faster compared to results generated with ReEDS2.0 inputs. Furthermore, between Scenarios 2 and

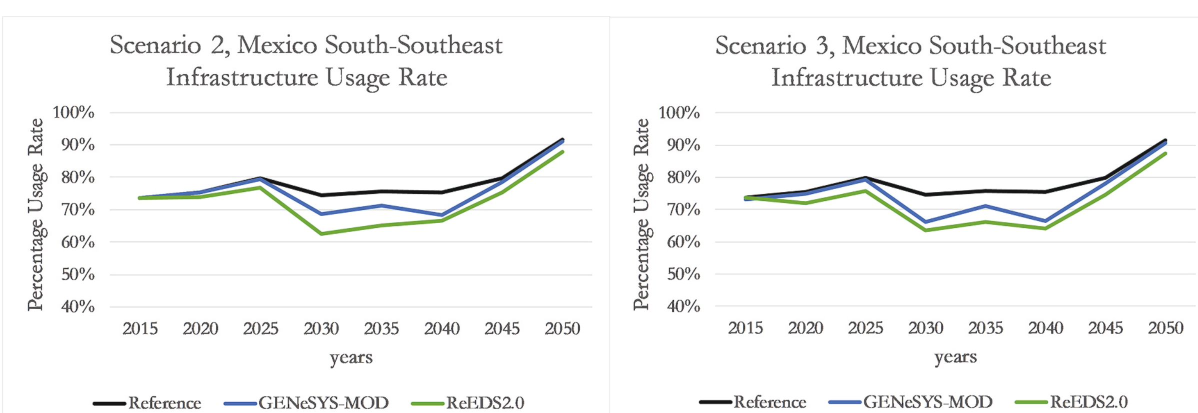

Fig. 7. NANGAM results. Percentage production infrastructure usage rate for Mexico South-Southeast in Scenarios 2 (left) and 3 (right) for inputs from different models.

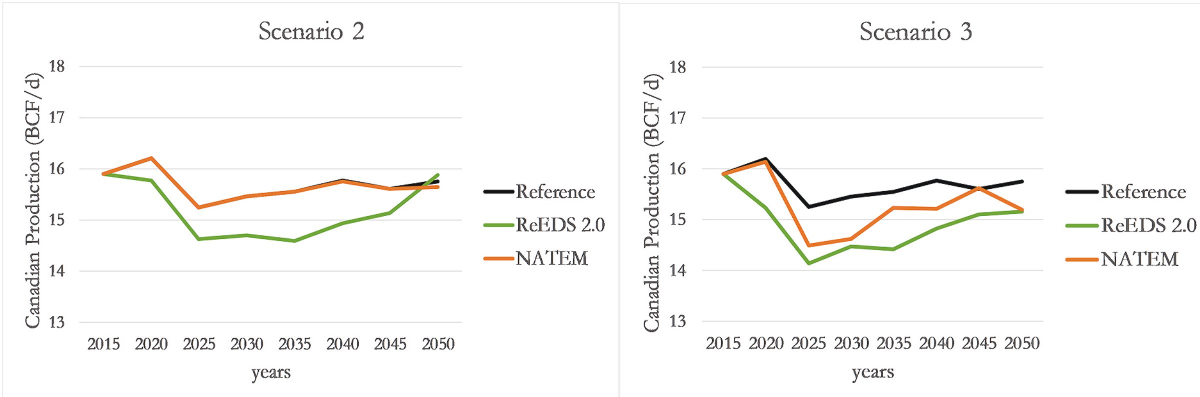

Fig. 8. NANGAM results. Canadian natural gas production in Scenarios 2 (left) and 3 (right) for inputs from different models.

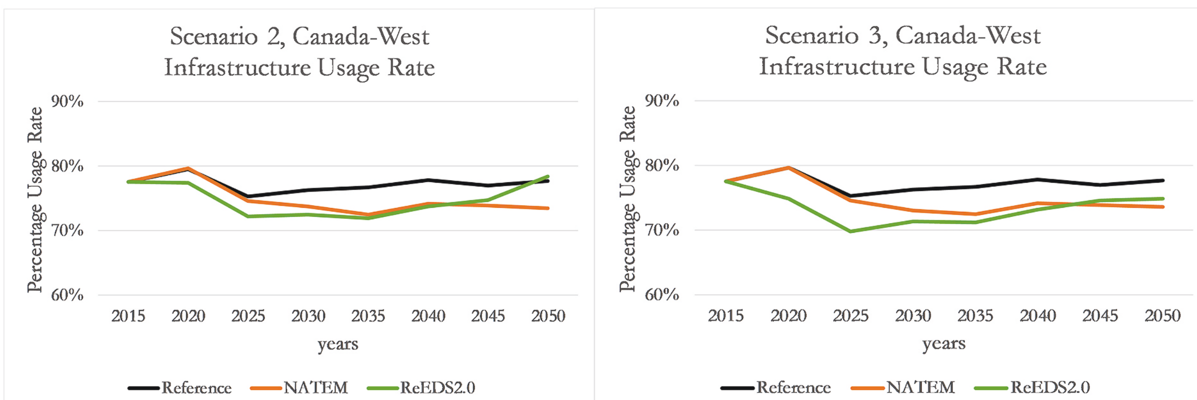

Fig. 9. NANGAM results. Percentage production infrastructure usage rate for Canada-West in Scenarios 2 (left) and 3 (right) for inputs from different models.

3, U.S. natural gas production does not change significantly using NEMS-AEO2019 inputs, and decreases by 16.74 BCF/d using ReEDS2.0 inputs in 2050. Investment in new production infrastructure adjusts accordingly. In Scenario 2, investment in new production infrastructure capacity decreases by 21% using NEMS-AEO2019 inputs and by 24% using ReEDS2.0 inputs, compared to the reference scenario. In Scenario 3, investment in new production infrastructure capacity decreases by 23% using NEMS-AEO2019 inputs and by 31% using ReEDS2.0 inputs, compared to the reference scenario. Fig. 5 shows that the decrease in investment in new infrastructure is heterogeneous between major producing regions for ReEDS2.0 but not for NEMS-AEO2019 inputs.

Mexican natural gas production decreases the most in 2030 when using inputs from either ReEDS2.0 or GENeSYS-MOD for both Scenarios 2 and 3, as shown in Fig. 6. More specifically, in Scenario 2 natural gas production decreases by 15% and by 6.5% when using inputs from ReEDS2.0 and GENeSYS-MOD respectively and are equivalent to 0.6 BCF/d and 0.25 BCF/d. Long-term Mexican production in Scenario 3 is comparable to that of Scenario 2 for both GENeSYS-MOD and ReEDS2.0 inputs. In the case of Mexico, infrastructure investment remains unchanged for Mexico South-Southeast, the major producing region. Fig. 7 shows that the decreased production is met with a decreased usage rate of existing infrastructure instead.

Finally, Fig. 8 summarizes the changes in Canadian natural gas production. Natural gas production using inputs from NATEM barely

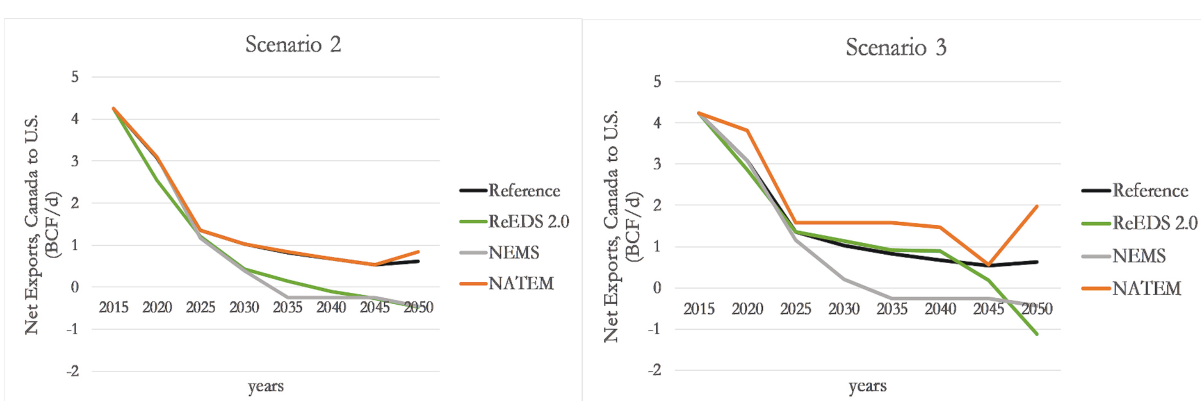

Fig. 10. NANGAM results. Net Exports of natural gas from Canada to the U.S. in Scenarios 2 (left) and 3 (right) for inputs from different models.

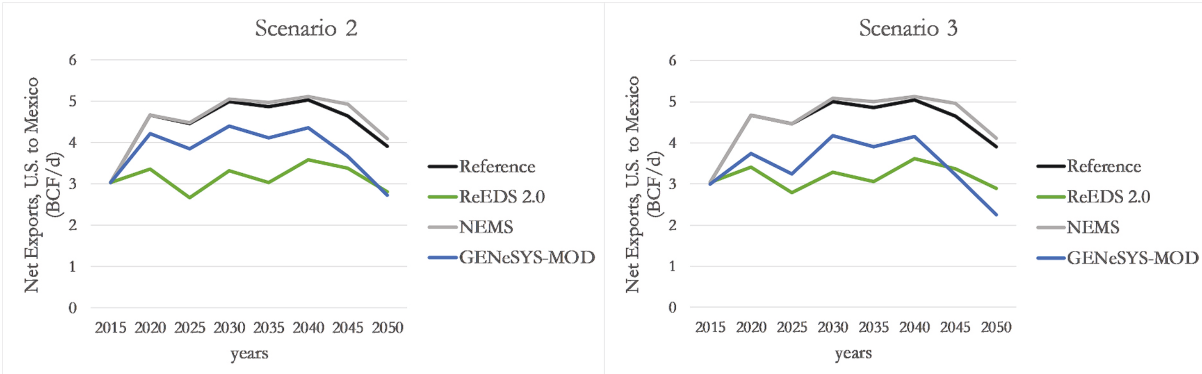

Fig. 11. NANGAM results. Net Exports of natural gas from the U.S. to Mexico in Scenarios 2 (left) and 3 (right) for inputs from different models.

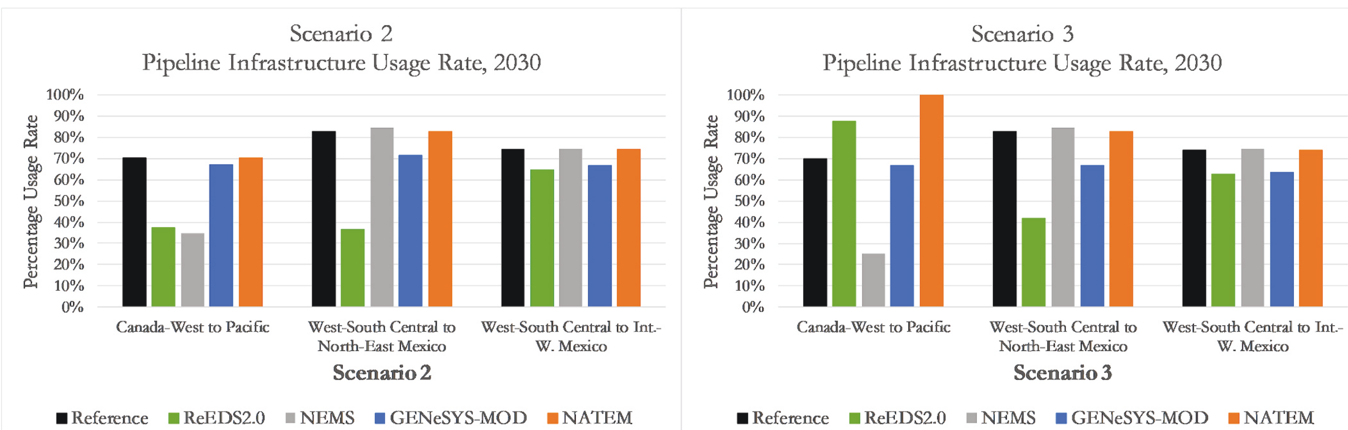

Fig. 12. NANGAM results. Percentage pipeline infrastructure usage rate for major inter-country pipeline interconnections in Scenarios 2 (left) and 3 (right) for inputs from different models in 2030.

adjusts for both Scenarios 2 and 3 compared to Reference. The natural gas production profile of NATEM follows projections from the National Energy Board (NEB, 2017). NATEM's Reference scenario is based on optimistic assumptions on the access of North American natural gas to markets outside North America. Consequently, the option to export excess natural gas internationally in the form of Liquified Natural Gas (LNG) results in small adjustment of natural gas production when demand from the electricity sector decreases in NATEM. On the other hand, for ReEDS2.0 inputs, Canadian natural gas production decreases by 6.2% in Scenario 2 in 2035 and by 7.2% in Scenario 3 in 2035 before converging to reference production by 2050. The nadir of Canadian consumption is 14.59 BCF/d in Scenario 2 and 14.42 BCF/d in Scenario 3. Similar to Mexico, West Canada, the major natural gas producing region in Canada, meets the decreased production by adjusting the usage rate of existing infrastructure, as shown in Fig. 9.

Net exports of natural gas from Canada to the U.S., reported in Fig. 10, adjust downwards as a result of reduced demand for natural gas in the U.S. For NATEM inputs, net Canadian exports to the U.S. in Scenario 2 follow the Reference and even increase by 0.22 BCF/d in 2050, whereas in Scenario 3 net exports decrease more aggressively compared to Reference. Net exports of natural gas of Canada to the U.S. increase, compared to reference, only when using inputs from NATEM, starting from 2020.

On the other hand, for NEMS-AEO2019 and ReEDS2.0 inputs, Canada becomes a net importer by 2050, importing approximately 0.50 BCF/d in Scenario 2. Moreover, production projections do not change significantly between Scenarios 2 and 3 for NEMS-AEO2019 inputs. However, when using ReEDS2.0 inputs, Canada transforms from a net exporter to a major net importer of U.S. natural gas. In this case, in 2050 Canada imports a net of 1.13 BCF/d from the U.S. We will return to this result in the next subsection.

Fig. 11 illustrates how net U.S. exports to Mexico are more resilient to changes in coordination of RPS policies. When applying inputs from NEMS-AEO2019, net exports of natural gas from the U.S. to Mexico increase with respect to Reference in both scenarios by an average of 2.10% in 2050. On the other hand, net U.S. natural gas exports to Mexico decrease when applying inputs from ReEDS2.0 and GENeSYS-MOD. The last two sets of results converge to net exports close to 2.50 BCF/d in 2050 in Scenario 2 but follow different trajectories. When using inputs from GENeSYS-MOD, net exports increase by 2040 before decreasing. Conversely, when using inputs from ReEDS, net exports oscillate around a mean of 3 BCF/d. In Scenario 3 net natural gas exports from the U.S. to Canada reach their nadir in 2050 when they decrease by 42% for GENeSYS-MOD inputs and by 26% for ReEDS2.0 inputs compared to the Reference scenario. Investment in new inter-country pipeline infrastructure remains unchanged. That is because the existing infrastructure suffices to cover trade needs under scenarios where demand is decreased. What adjusts instead is the usage rate of certain pipeline infrastructure. Fig. 12 shows the adjustment of the usage rate of major pipeline interconnections in 2030.

In conclusion, we observe that country-level natural gas production and cross-border trade vary significantly depending on the model providing the natural gas consumption projections. Natural gas production of Mexico in Scenario 2 exhibits the highest variation for inputs from all models and can decrease up to 15% compared to Reference. The decrease in natural gas production results in a decrease in production infrastructure usage rate. Furthermore, we observe that inputs from ReEDS2.0 lead to larger changes in production and trade with respect to

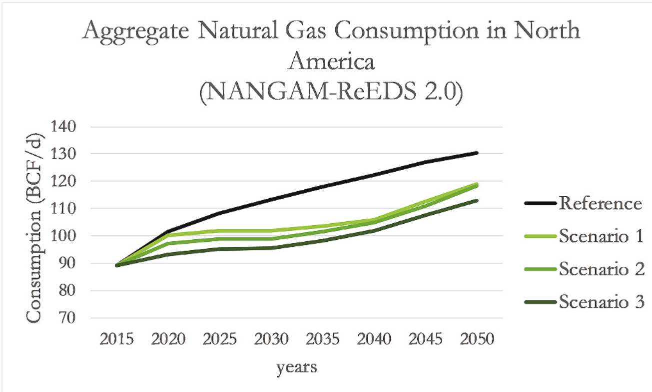

Fig. 13. NANGAM results using ReEDS2.0 inputs. Aggregate consumption of natural gas in North America for all scenarios.

results that were generated using inputs from all other models. The last is true for all countries and all scenarios. The reasons are two. First, ReEDS2.0 reports the largest change in demand among all models, which subsequently results in larger adjustment of natural gas production in all three countries. Second, as shown in Fig. 1, ReEDS2.0 provides regional change in natural gas consumption for all three countries, whereas the rest of the models provide country-level changes for a single country each. This implies that the change in demand in ReEDS2.0 is regionally more heterogeneous compared to the rest.

5.2. Coordination between all countries

Scenario 1 requires the representation of all three countries within a single model. The only model in this study with that level of disaggregation is ReEDS2.0. In this section, we focus on the findings that come from using ReEDS2.0 inputs in order to compare results between scenarios. In Fig. 13 we can verify that greater coordination among countries in North America mitigates the impact of RPS on natural gas consumption, which is consistent with microeconomic theory. In addition, natural gas infrastructure implications are similar between Scenario 2 and Scenario 3.

Country-level consumption follows the same trend for all countries up to 2040, as shown in Figs. 14–16. The only exception is natural gas consumption in Canada for Scenarios 2 and 3, after 2040. Before explaining this last finding, we need to clarify that findings deep into the timeline are subject to greater uncertainty. We will first examine the changes in natural gas consumption of each country. In Scenario 3, demand for natural gas in Canada increases in 2050 by 1.18 BCF/d, or 7.94%, compared to the Reference scenario. Canada already meets the RPS requirements given the existing hydro. Constraining trade of RECs to the subnational level means that all North American regions other than Canada cannot tap into the low-cost hydro potential of Canada in the long term. Therefore, in the power sector in Scenario 3, the increased demand for Canadian power supply in the long term is met by increasing gas-fired capacity and production, which in turn increases demand for natural gas in Canada. Hence, lack of RPS coordination between North American countries and regions increases long-term natural gas consumption in Canada.

In the U.S., for Scenario 3, consumption decreases by 21% or 17.55 BCF/d, in 2050, which drives production to decrease by 15%, or 16.47

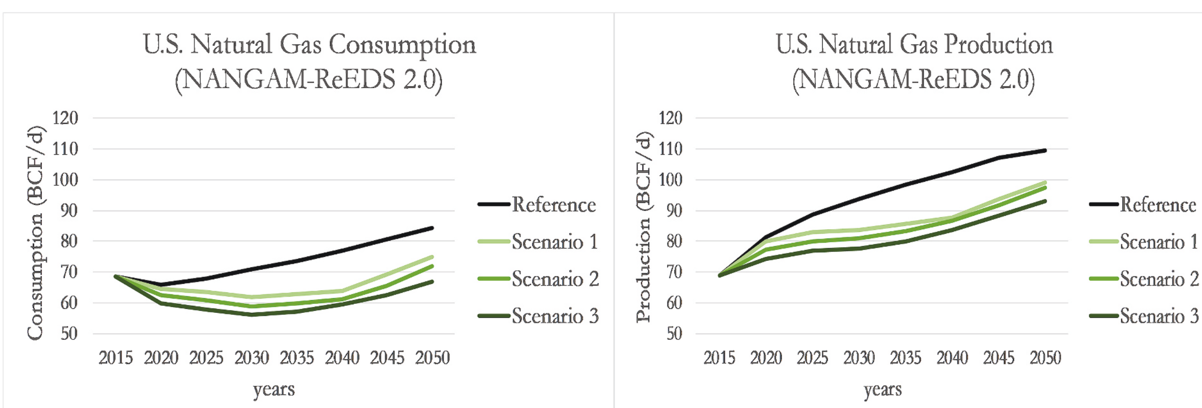

Fig. 14. NANGAM results using ReEDS2.0 inputs. U.S. natural gas consumption (left) and production (right) under Renewable Portfolio Standards.

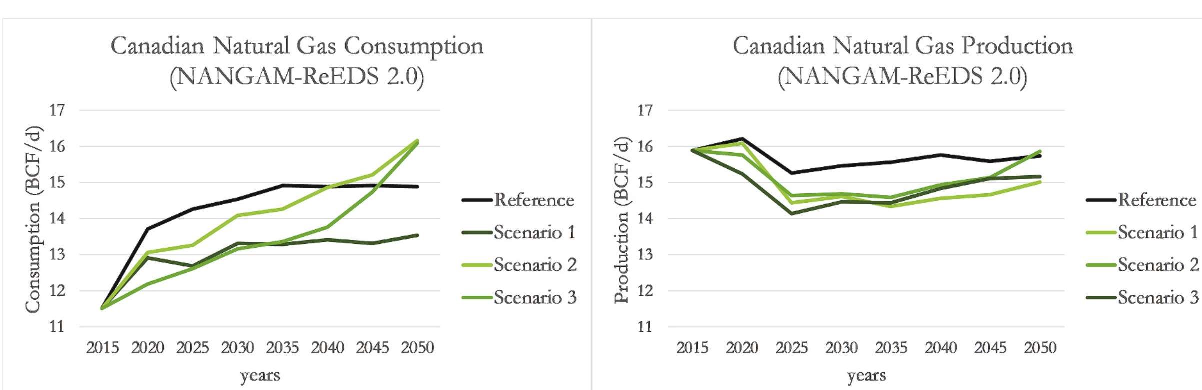

Fig. 15. NANGAM results using ReEDS2.0 inputs. Canadian natural gas consumption (left) and production (right) under Renewable Portfolio Standards.

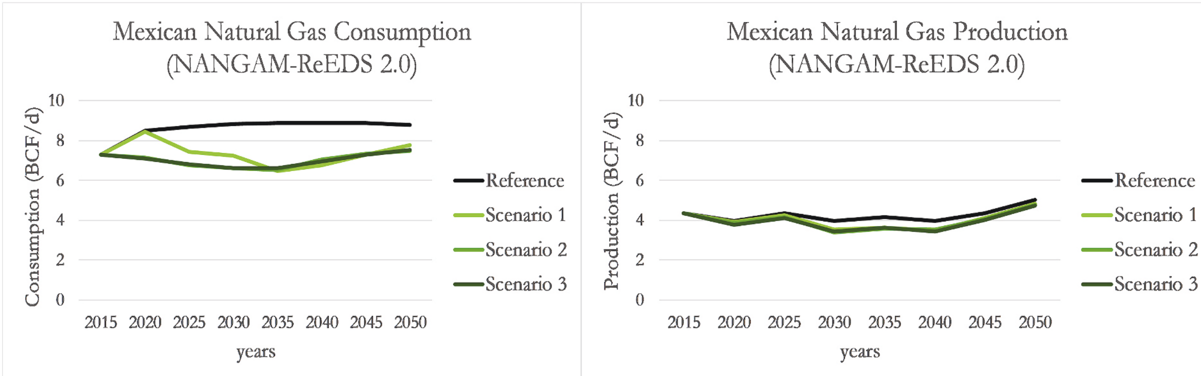

Fig. 16. NANGAM results using ReEDS2.0 inputs. Mexican natural gas consumption (left) and production (right) under Renewable Portfolio Standards.

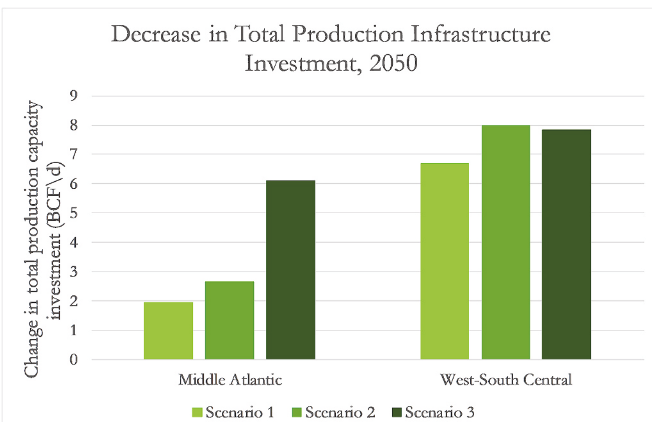

Fig. 17. NANGAM results using ReEDS2.0 inputs. Decrease in regional natural gas production infrastructure investment by 2050 in the U.S. in all scenarios, compared to the reference scenario.

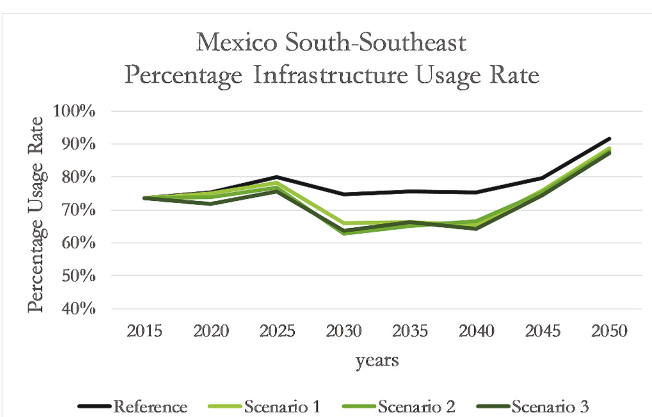

Fig. 18. NANGAM results using ReEDS2.0 inputs. Mexico South-Southeast production infrastructure usage rate for all scenarios and years.

BCF/d, in 2050 compared to Reference. The regional heterogeneity of the shock in 2050 implies that low-cost U.S. resources that were exploited in the Reference scenario to satisfy domestic demand are in abundance in this scenario and available to be exported instead. Consequently, Canadian natural gas production remains relatively unchanged. Net exports of the U.S. to Canada in 2050 amount to 1.13 BCF/d. Therefore, part of the increase in natural gas consumption in Canada is supplied by low-cost U.S. natural gas production.

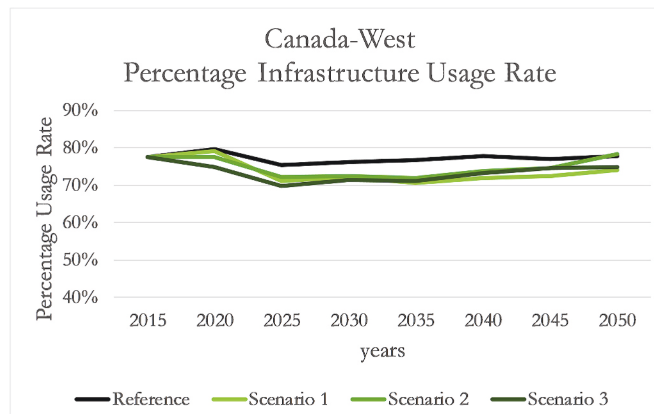

Fig. 19. NANGAM results using ReEDS2.0 inputs. Canada-West production infrastructure usage rate for all scenarios and years.

Fig. 17 highlights that the adjustment of U.S. infrastructure due to RPS is regionally heterogeneous. In all three scenarios, investment in new production infrastructure capacity in Middle Atlantic decreases less than that of West-South Central. Moreover, greater RPS coordination results in milder decrease in new infrastructure investment compared to the reference scenario. On the other hand, Canada and Mexico choose to adjust the usage rate of existing production infrastructure. Figs. 18 and 19 show that for both countries, greater RPS coordination results in a higher infrastructure capacity utilization rate for the major producing regions of each country.

Fig. 20 summarizes all net exports from the U.S. to Mexico and from Canada to the U.S. We observe that net exports from the U.S. to Mexico benefit in the short term from higher coordination of RPS between countries. Net exports in Scenario 1 are greater compared to Scenarios 2 and 3 by approximately 36% in 2020, 20% in 2025, 14% in 2030, and 7.6% in 2050. Between 2035 and 2045, net exports of U.S. to Mexico are approximately 7% lower in Scenario 1 compared to Scenarios 2 and 3. Moreover, net exports of Canada to the U.S. decrease for scenarios 2 and 3 in the long-term and the U.S. becomes a net exporter of natural gas to Canada in 2050, as explained above.

The changes in natural gas trade between the U.S. and Canada highlight that trade between individual regions does not necessarily decrease when natural gas demand in the two regions decreases. What is also important is the regional heterogeneity of the decrease in demand. More specifically, Canadian natural gas consumption decreases in the short and medium-term but increases in the long-term in Scenarios 2 and 3 compared to reference consumption. At the same time, the decrease in U.S. demand means that cost-efficient domestic resources are no longer needed for domestic use. The available U.S. natural gas production is

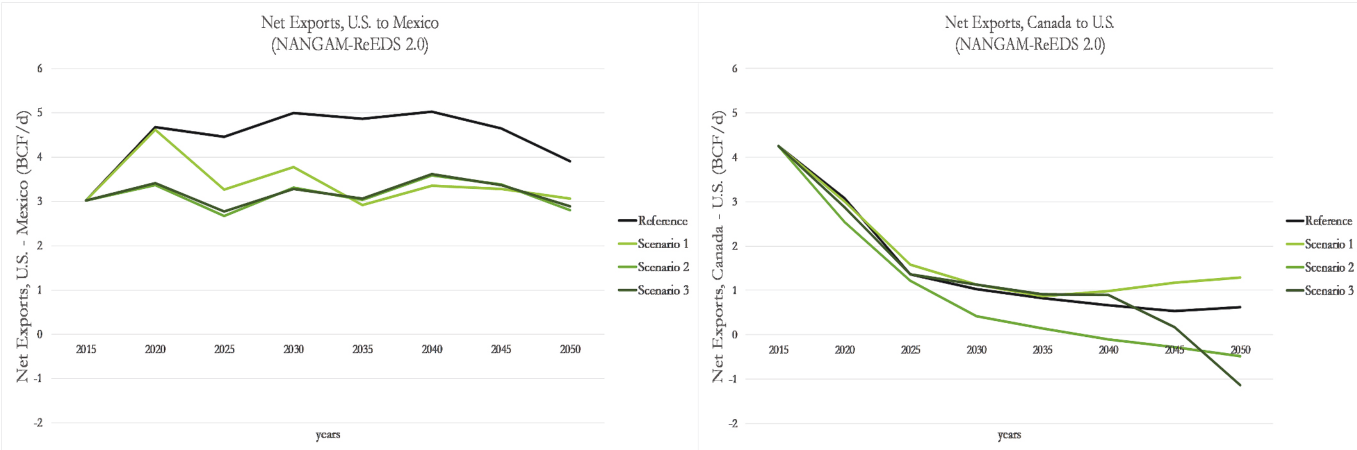

Fig. 20. NANGAM results using ReEDS2.0 inputs. Net natural gas exports of U.S. to Mexico (left) and Canada to the U.S. (right) for all scenarios and years.

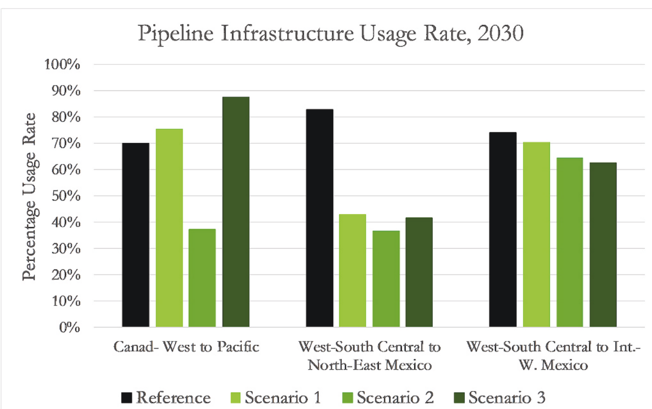

Fig. 21. NANGAM results using ReEDS2.0 inputs. Infrastructure usage rate for major inter-country pipeline interconnections for all scenarios in 2030.

more competitive than Canadian natural gas production, leading to an increase in long-term U.S. exports to Canada. Increased Canadian natural gas consumption is met by U.S. natural gas production and the U.S. becomes a net exporter of natural gas in 2050. Net trade, in absolute value, increases by 84% in Scenario 3 compared to Reference. The different trade level between countries is met by adjusting the usage rate of existing pipeline infrastructure. Fig. 21 shows that the adjustment of the usage rate of pipeline infrastructure follows the same trend as the adjustment of trade.

Finally, RPS coordination at the international level results in smaller discrepancies of U.S. natural gas prices when compared to Reference, as shown in Fig. 22. In Scenario 1 all countries experience the highest reduction in consumption prices at 2040. At that year, U.S. natural gas retail prices decrease by 11.88%, Canadian retail prices decrease by 7.29%, and Mexican retail prices decrease by 9.29% with respect to Reference. On the other hand, in Scenario 3, the deviation of retail prices is close to the highest for all countries in 2035 compared to Reference. U. S. natural gas retail prices decrease by 12.7%, Canadian retail prices decrease by 6.6%, and Mexican retail prices by 9.23%.

6. Conclusion and policy implications

This study explores the impact of RPS on natural gas markets under varying regional RPS coordination. We implement a scenario of a joint market for RECs for the U.S., Canada, and Mexico, a scenario of three individual country-level markets, and a scenario in which RECs are traded only by electricity producers within the same region of a country. RPS generally displace gas-fired producers along with other emitters. However, greater RPS coordination allows regions with low renewables potential to exploit the renewable energy credits of their neighbors, thus allowing for greater investment in gas-fired generation in North America on aggregate. Under the same RPS coordination scheme, projections of natural gas consumption will differ when derived using models that are based on different assumptions. For that, we conduct our analysis using four models with bottom-up representation of the electricity market. We derive the change in natural gas consumption by simulating the effect of RPS targets on the power mix of the U.S., Canada, and Mexico. The change in natural gas consumption of each model with respect to its Reference is then fed into NANGAM to generate natural gas infrastructure expansion trajectories for each country.

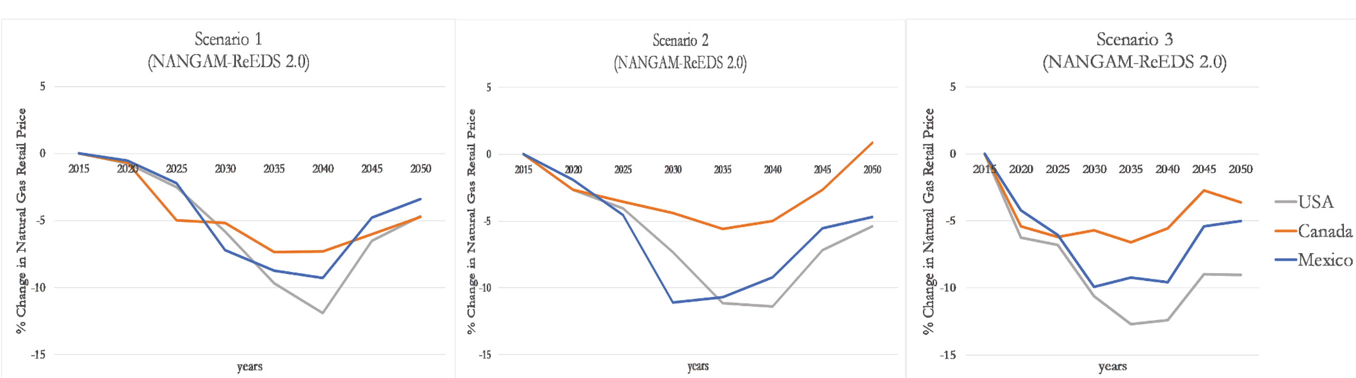

Fig. 22. NANGAM results using ReEDS2.0 inputs. Percentage change in retail natural gas prices relative to the Reference scenario in the U.S., Canada, and Mexico.

We find that natural gas infrastructure development is sensitive to model-specific projections of natural gas consumption. Most notably, in Scenarios 2 and 3, the U.S. is projected to become a net exporter to Canada when coupling NANGAM to ReEDS2.0 or NEMS-AEO2019. Moreover, natural gas infrastructure development is also sensitive to renewable policy coordination assumptions. U.S. production infrastructure adjusts heterogeneously, depending on the region. Major producing regions in Canada and Mexico adjust their production infrastructure usage rate instead. In most cases we do not observe significant changes in production and cross-border trade when we switch from a country-level to a regional-level RPS coordination scheme. However, this is not true when we use inputs from ReEDS2.0; we observe that greater regional participation in a RPS coordination scheme mitigates the impact on natural gas production, trade, and prices.

We find that no country's natural gas production is higher intertemporally when RPS policies are introduced. On the other hand, lower production with respect to Reference implies that not all regional cost-efficient natural gas resources are exploited. Among all scenarios, U.S. production infrastructure investment, as well as Canadian and Mexican production infrastructure usage rate, decrease the least in Scenario 1. In the case of cross-border natural gas trade between Canada and the U.S. in Scenario 3, the decrease in natural gas demand in the U.S. is higher than that of Canada. This creates a surplus of competitive available natural gas production in the U.S. that can be exported to Canada. More generally, when the natural gas markets of the three countries are fully integrated but their RPS policies are not coordinated, there is a tradeoff between lower regional demand for natural gas due to RPS but potentially higher trade due to availability of low-cost natural gas production in neighboring regions. Investment in inter-country pipeline infrastructure remains unchanged and pipeline operators choose to respond to the shock by operating at a lower capacity usage rate.

We also find that lack of coordination of RPS schemes results in higher discrepancies in U.S. natural gas prices as compared to Reference. Consumption of natural gas decreases the most when RECs can-not be traded outside a region in contrast to scenarios where RECs can be traded at the country or at the international level. Decrease in short-term consumption results in a decrease of natural gas prices. However, a decrease in natural gas prices renders natural gas competitive for a longer period of time compared to other power generation technologies and thus increases consumption in the long-term. We propose that further research be conducted to understand how RPS coordination affects consumption of natural gas by studying the natural gas and electricity sectors in a single framework.

Our analysis at this point is limited by the one-way link between the electricity and natural gas models. RPS reduce the price of natural gas which would increase investment in natural gas-fired plants and mitigate the impact of RPS on natural gas consumption, if a representative feedback from the natural gas model back to the electricity models existed. For that, our analysis of the natural gas sector is a bounding scenario, as we don't consider feedback from natural gas markets into the electricity sector. Nevertheless, the results reveal the tradeoff between lower consumption but greater U.S.-Canada cross-border trade of natural gas as a result of more stringent RPS targets.

Moreover, in our analysis we treat LNG trade as exogenous. U.S. LNG exports are growing rapidly, with 9.64 BCF/d extra liquefaction capacity being installed by 2020. In addition, net LNG exports are expected to amount to 5.02 BCF/d by 2050 per the 2019 Annual Energy Outlook (EIA, 2019a). Therefore, the treatment of LNG as exogenous implies that natural gas producers are deprived of the option to sell in the international market when North American demand decreases. The fact that producers would have the option to export natural gas outside North America does imply in a straightforward manner that LNG exports would increase, as this is a market outcome. Therefore, proper treatment of LNG trade requires modeling of the global market (Moryadee et al., 2014), which is out of the scope of this paper that focuses on North American production and pipeline infrastructure. Since our modeling assumption constraints the available options of North American producers, the results on production and production capacity can be viewed as a worst-case scenario at the national level. Future research needs to study the sensitivity of the regional results to assumptions regarding LNG infrastructure.

Finally, RPS also contribute in the decrease of CO_2 emissions both in the electricity and in the natural gas sector. Therefore, there exists a tradeoff between the cost of RPS that is incurred by different agents in the electricity and natural gas sectors and the social benefit of emissions reduction. As the focus of this study has been on infrastructure development, future research can address how the changes in lifecycle emissions for the different RPS coordination schemes impact welfare.

Our results establish the impact of RPS on natural gas markets and natural gas infrastructure. We emphasize the importance of coordinating RPS policies for North American natural gas production. We study three scenarios that assume different levels of coordination of RPS among the U.S., Canada, Mexico, and their regions. By coupling models with detailed representation of the electricity sector with NANGAM we are able to identify the tradeoff between regional natural gas production and trade. By receiving inputs from four different models we are able to test our findings against different assumption on the electricity sector. We conclude that fine-tuning stringent RPS policies in the electricity sector can prove critical for the timeline of retirement of natural gas infrastructure.

CRediT authorship contribution statement

Charalampos Avraam: Conceptualization, Methodology, Software, Validation, Formal analysis, Data curation, Writing - original draft, Writing - review & editing, Visualization. **John E.T. Bistline:** Software, Validation, Data curation, Writing - review & editing, Funding acquisition. **Maxwell Brown:** Software, Validation, Data curation, Funding acquisition. **Kathleen Vaillancourt:** Software, Validation, Data curation, Funding acquisition. **Sauleh Siddiqui:** Conceptualization, Methodology, Writing - original draft, Writing - review & editing, Supervision, Project administration, Funding acquisition.

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.

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Appendix A. Implemented % change in total natural gas consumption

The percentage change in total natural gas consumption used as input to NANGAM from every model and for each country and scenario is detailed below.

	Mexico, GENeSYS-MOD							
	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 2	0.00	−4.10	−5.47	−7.74	−8.57	−9.04	−9.08	−10.60
Scenario 3	0.00	−8.36	−10.92	−11.08	−10.44	−11.78	−13.13	−14.78
Mexico, ReEDS2.0								
	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 1	0.00	−0.82	−11.62	−15.49	−22.61	−20.49	−14.72	−9.39
Scenario 2	0.00	−12.65	−17.76	−21.72	−22.43	−18.05	−14.31	−12.22
Scenario 3	0.00	−13.89	−17.69	−21.39	−21.48	−18.74	−14.84	−12.12
Canada, NATEM								
	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 2	0.00	−0.07	−0.05	−0.06	−0.04	−0.07	0.00	−1.85
Scenario 3	0.00	−4.64	−6.40	−8.49	−6.06	−7.67	0.00	−10.87
Canada, ReEDS2.0								
	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 1	0.00	−0.39	−6.97	−6.28	−8.34	−9.47	−9.57	−8.32
Scenario 2	0.00	−0.05	−3.49	−1.97	−2.80	−1.40	1.07	6.63
Scenario 3	0.00	−5.89	−7.68	−7.22	−7.89	−7.24	−1.39	5.20
U.S., NEMS-AEO2019								
	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 2	0.00	0.17	−2.75	−6.35	−10.50	−11.34	−12.73	−12.86
Scenario 3	0.00	−0.07	−2.80	−8.01	−11.81	−12.54	−13.72	−13.78
U.S., ReEDS2.0								
	2015	2020	2025	2030	2035	2040	2045	2050
Scenario 1	0.00	−1.51	−5.63	−10.73	−13.51	−15.71	−12.61	−9.84
Scenario 2	0.00	−4.80	−9.68	−15.01	−17.17	−18.64	−16.63	−13.11
Scenario 3	0.00	−8.37	−12.99	−18.04	−20.23	−20.62	−19.66	−18.61

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