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The economic impacts of high wind penetration scenarios in the United States

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A B S T R A C T

The U.S. electric sector is experiencing rapid increases in renewable generation with an expectation of continued growth. We examine the impacts of increased wind electricity on the U.S. economy using a hybrid model that links a detailed electric sector model (the National Renewable Energy Laboratory's Regional Energy Deployment System [ReEDS]) with a computable general equilibrium model of the U.S. economy (the Massachusetts Institute of Technology's U.S. Regional Energy Policy [USREP] model). Increasing wind capacity displaces fossil fuels for electricity generation, which depresses fossil fuel prices and reduces economy-wide CO2 emissions. Competitive wind deployment in the reference scenario achieves these outcomes with lower electricity prices than a scenario with wind capacity fixed at 2016 levels. Lower fossil fuel and electricity prices benefit low-income households, but the dominant economic impacts are driven by increased electric sector investment and capital returns, which primarily benefit those with higher incomes. Overall, cost-competitive wind provides benefits to the U.S. economy that are initially low but rise beyond 2030 to achieve cumulative welfare and GDP improvements of $110 and $111 billion through 2050.

Prescribing additional wind deployment (meeting 35% of demand by 2050) increases post-2030 electricity prices but not more so than keeping wind capacity fixed at 2016 levels. The negative effect of higher prices on welfare, however, is outweighed by higher returns from the additional wind investment. While these changes favor higher income classes, we find economy-wide benefits through 2040. These benefits diminish by 2050, but the cumulative additional gains through 2050, beyond the reference case, are $192 billion in welfare and $150 billion in GDP.

1. Introduction

Renewable energy has recently seen rapid growth in the electric sector, in the United States and throughout the world (EIA, 2017a; REN21 2016, 21). Most of this growth comprises wind and solar photovoltaic (PV) technologies (Bolinger and Seel, 2016; Wiser and Bolinger, 2016). Wind and PV supplied 7% of U.S. electricity in 2016, and the potential for much higher wind and PV penetration in the future has sparked broad interest in understanding the implications of such an electricity system (EIA, 2017b). The appetite for better understanding these impacts has been made stronger by recent events where variable renewable energy sources (primarily wind) have reached high shares of the generation mix, such as 26% of generation in the Electric Reliability Council of Texas system in March 2017 and 52% in the U.S. Southwest Power Pool system on February 12, 2017 (Martin, 2017; ERCOT, 2017). These events suggest that the constraints on high penetration systems are not likely to be technical and that a better understanding of their economic impacts is worthwhile.

This article focuses on the economic impacts of high wind penetration using a scenario for the contiguous United States derived from the U.S. Department of Energy (DOE) *Wind Vision Central Study Scenario* (referenced throughout as the *Study* or *Study Scenario*) (DOE, 2015; Lantz et al., 2016; Wiser et al., 2015; Wiser et al., 2016a). This scenario is introduced in the DOE-led *Wind Vision* report, which explores a range of electric sector scenarios with high wind penetration and defines a long-term vision for the industry based on a thorough analysis and stakeholder engagement process. The effect of high variable renewable penetration on electricity system operation, including grid reliability and operating cost, has been analyzed extensively in a series of integration studies at the National Renewable Energy Laboratory (NREL) and others, but the economic component of these analyses is limited to electric sector operating costs (Lew et al., 2013; Bloom et al., 2016; Brinkman et al., 2016). The *Wind Vision* report goes beyond

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electric sector operating costs to look at long-term cumulative capital and operating costs in the electricity system, and it additionally considers the economic value of greenhouse gas and air pollution reductions associated with wind growth (DOE, 2015). Direct and induced jobs and workforce impacts resulting from wind capacity expansion are also assessed for the *Wind Vision* scenarios, but these do not incorporate net impacts on other industries and sectors. Other analyses have similarly looked at the impacts of growth in solar energy and hydropower (DOE, 2016; Wiser et al., 2016b). While these analyses use detailed bottom-up tools to examine economic impacts of the electric sector for several decades into the future, they do not include a full multi-sectoral economic analysis that captures the whole U.S. economy. Thus, these analyses do not assess net economic impacts that account for the response of other sectors to changes in the electric sector.

Some studies have provided multisector analyses of the U.S. and other economies under high variable renewables penetration, examining renewable energy policy incentives, employment effects, and welfare impacts at the national level (Böhringer et al., 2013; Babiker and Eckaus, 2007; Lehr et al., 2008; Rausch and Reilly, 2015; Lehr et al., 2012). However, most have relied on top-down equilibrium or input-output models that do not consider technology-specific cost and performance detail in energy producing or consuming sectors. Lacking bottom-up electricity sector detail in addition to high spatial and temporal resolution, these analyses are unable to account for the heterogeneity inherent in renewable resource quality and how renewables interact with other generation and transmission resources in the system. These characteristics are important for accurately modeling the cost and energy production of renewable resources, which influence market behavior of the electric sector and the economy as a whole. For example, top-down models could be biased towards variable renewable technologies on a cost basis alone because they have difficulty representing the effect of curtailments and capacity value while considering how these characteristics vary with space, time, and deployment. It is also difficult for top-down economic models to account for the dynamic nature of technology development and the resulting effect on technology cost and performance over time, such as that experienced in recent years by the wind and PV industries (Barbose et al., 2017; Wiser and Bolinger, 2016).

The limitations of bottom-up electric sector and top-down economic approaches can be partially overcome with a linked model integrating the two approaches (Manne, 1977; Hourcade et al., 2006; Böhringer, 1998; Böhringer and Rutherford, 2005). The present work uses a linked model that joins a top-down model of the U.S. economy (USREP) with a bottom-up capacity expansion model of the electricity sector (ReEDS). ReEDS, the Regional Energy Deployment System, is a capacity expansion model for the contiguous United States developed by NREL. USREP, the U.S. Regional Energy Policy model, is a computable general equilibrium (CGE) model of the U.S. economy developed by the Massachusetts Institute of Technology (MIT). In the linked model, ReEDS results provide detailed electric sector variables to USREP, and USREP provides economic variables to the electric sector that ReEDS uses to maximize surplus in the electric sector. The linked model iterates on this information in each 2-year solution period until convergence in national electricity demand is achieved, and this process continues throughout a 2010–2050 study period. When linked together, the models allow us to explore the impact of alternative electricity sector scenarios across all sectors of the U.S. economy while capturing detailed electric sector behavior in ReEDS and sub-national and distributional economic impacts in USREP.

These two models were first coupled for a 2014 study that explores the economic impacts of clean and renewable electricity standards in the United States (Rausch and Mowers, 2014). Building upon that work, the present analysis links newer versions of both models to take advantage of continued development of features and data in both ReEDS and USREP. More recent projections for technology costs, renewable and fossil resources, and economic growth have been included using data sources such as the 2016 U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) and the 2016 NREL Annual Technology Baseline (ATB) (EIA, 2016; Cole et al., 2016a). Current policies such as renewable energy tax credits and portfolio standards are also included.

This work focuses specifically on the economic impacts of wind deployment in the United States by comparing scenarios with (1) reference cost-competitive wind deployment, (2) no wind deployment after 2016, and (3) high wind deployment. By integrating ReEDS into the USREP CGE model, we study feedbacks between wind deployment, markets for electricity and fossil fuels, and economic impacts on the total U.S. economy. Relative to analyses that focus on detailed power plant and electric grid responses to wind deployment, the integrated model also allows assessments of impacts on household welfare as well as regional impacts of wind investment.

1.1. The Wind Vision scenarios

This section describes key scenario characteristics, while the Methodology section goes into greater detail on model and data specifics. Three scenarios derived from the *Wind Vision* report are compared in this analysis.

1) The *Business-as-Usual Scenario* using all reference model assumptions.
2) The *No New Wind Scenario* prohibiting new wind deployment beyond 2016 capacity.
3) The *Study Scenario* with high wind deployment as in the *Wind Vision Central Study Scenario*.

The *Business-as-Usual Scenario* includes all reference data and assumptions for both ReEDS and USREP with no additional constraints on the electric sector beyond those representing existing technology, market, and policy considerations (details in Section 2). As is common in the literature, we use the *Business-as-Usual Scenario* as a reference point for comparison to other scenarios.

The *No New Wind Scenario* is modeled similarly to the *Central Baseline Scenario* in the *Wind Vision* report. In this scenario, no new wind generating capacity is permitted to be deployed beyond announced builds through 2016. All other assumptions are identical to the *Business-as-Usual*. This scenario is not intended to portray a probable electric sector outcome or a particular policy.[1] While results in the main text of this paper use the *Business-as-Usual Scenario* as a point of comparison, readers more interested in comparing outcomes relative to *No New Wind* can refer to the Supplemental information containing all results figures reproduced with the *No New Wind Scenario* as a reference point. This comparison isolates the impacts of all post-2016 wind deployment and identifies policy-agnostic effects separately from other market assumptions embedded in our *Business-as-Usual Scenario*.

The high wind penetration *Study Scenario* is defined consistently with the *Wind Vision* report's *Central Study Scenario*. This scenario is widely accepted by the wind industry as a representative future with continued advancement and expansion of wind capacity in the United States, making it a useful candidate for exploring the economy-wide impacts of wind deployment. The *Study Scenario* prescribes wind deployment beyond that deployed in the least-cost framework of the

[1] To eliminate the interactions between wind deployment and existing state-level renewable portfolio standards (RPS), this scenario also requires non-wind renewable growth to meet or exceed capacity deployed in the *Business-as-Usual* while relaxing state RPS constraints. Similarly, California Assembly Bill 32 (AB-32), which limits statewide CO_2 emissions, is adjusted in *No New Wind* by estimating the AB-32 CO_2 reduction attributable to wind generation and adding that quantity to the nominal AB-32 CO_2 limits to produce an adjusted AB-32 limit that reflects the inability to utilize wind generation for policy compliance. These two policy-specific adjustments allow better use of *No New Wind* to understand the impacts of wind deployment not driven by state RPS and AB-32 policies.

Business-as-Usual, with wind required to meet 10% of end-use electricity demand by 2020, 20% by 2030, and 35% by 2050. To put these values in context, wind generation comprised about 5.5% of total U.S. generation in 2016 (EIA, 2017b). To assess growth in the offshore wind industry, the share of offshore wind generation within total wind generation is required to be 3% in 2020 (0.3% of end-use demand), 10% in 2030 (2% of demand), and 20% in 2050 (7% of demand). Growth is prescribed along a linear trajectory between these milestones. Offshore wind is also required to be distributed across five offshore regions: North Atlantic, South Atlantic, Gulf of Mexico, Pacific, and Great Lakes. Special considerations are made for offshore wind due to the conservative nature of recent (2016) offshore wind cost and performance estimates relative to their land-based counterparts, which are partly a function of the relative immaturity of the U.S. and Global offshore wind industries and the technology's associated risk profile. The prescribed wind deployment is not accompanied by cost or performance improvements beyond the *Business-as-Usual Scenario*, which further isolates the impacts of the deployment itself rather than the coupled effects of wind deployment and assumed technological change.

Wind deployment is the only scenario variable discussed in this article. While the *Wind Vision* report also explored alternate fossil fuel costs and wind technology costs, the present analysis focuses on more comprehensively exploring the economic impacts from wind deployment.

2. Methodology

2.1. The linked ReEDS-USREP model

In this section, ReEDS and USREP model characteristics are described independently before a detailed description of how the models are coupled. The discussion is an update from Rausch and Mowers (2014) with an emphasis on features relevant to the *Wind Vision* scenarios (Rausch and Mowers, 2014).

2.1.1. Regional Energy Deployment System (ReEDS)

2.1.1.1. Model structure. ReEDS is a bottom-up electric sector capacity expansion model for the contiguous United States that finds the least-cost construction and operation of generation and transmission assets in the 2010–2050 study period. It is formulated as a linear program that solves in 2-year time steps sequentially throughout the study period. In standalone operation, the model objective minimizes the 20-year net present value of investments and operation in each time step. The sequential nature, combined with limited foresight, mean that solutions can be path dependent and do not represent a true intertemporal optimization for 2010–2050, but this construction allows for nonlinear calculations and parameter updates between solve years that better reflect true system operation. When linked with USREP, economic parameters from USREP can also be updated between solve years. In each solve year, ReEDS satisfies electricity demand and reserves requirements with a full suite of generation, storage, and transmission technologies while accounting for constraints imposed by power systems, the transmission network, resource availability, and policies.

ReEDS balances electricity supply and demand in 134 balancing area (BAs), the same spatial resolution used to represent generating capacity for all technologies except wind and CSP (Fig. 1). Wind and CSP resources are further resolved into 356 resource regions. While the model does not represent individual power plants or generating units, high regional resolution along with technology differentiation by subcategory, resource quality, and cost offers a high level of detail.

Within each 2-year solve, ReEDS implements a reduced-form electricity dispatch using 17 time slices, four for each season to represent the average diurnal load variation in that season plus an additional "superpeak" time slice comprised of the top 40 summer load hours to better characterize reserves requirements. While not the time-resolution of production-cost models that represent hourly or sub-hourly dispatch, ReEDS time slices aim to represent electricity system operating conditions with sufficient detail to make sensible capacity expansion decisions over the course of a multi-decadal period of analysis.

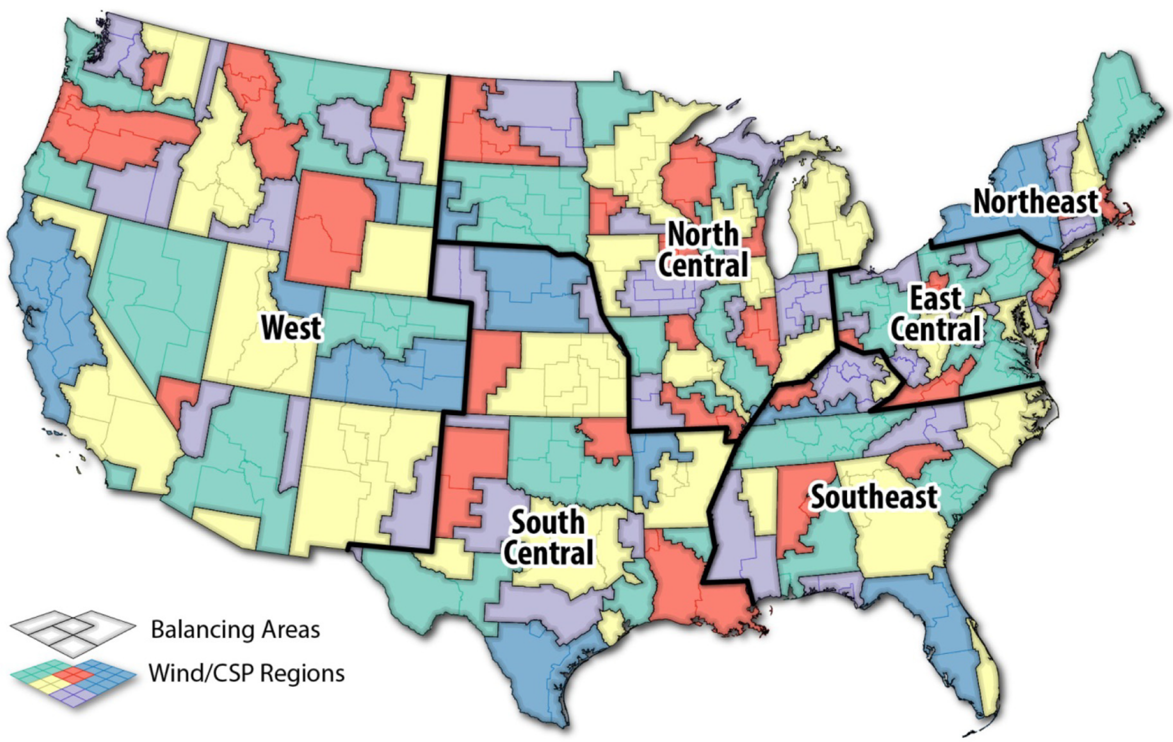

Fig. 1. ReEDS balancing area and wind/CSP resource region boundaries, with the six USREP U.S. sub-regions also labeled and denoted by thick black boundaries. USREP regions other than the West are abbreviated as: South Central = SCen, North Central = NCen, Southeast = SEas, East Central = ECen, Northeast = NEas.

A major strength of the ReEDS model is its representation of variable renewable electricity. The variability of wind, PV, and CSP without thermal storage are characterized by three key parameters: (1) capacity value (the amount of capacity assumed available at peak load), (2) induced operating reserve requirements due to forecast error, and (3) curtailed electricity. These parameters are calculated after each solve year based on expected value, variance, and inter-regional correlation of renewable energy production, making them a function of the capacity expansion solution as it evolves over time. In addition, interconnection costs for variable renewables are included using supply curves that consider the distance and cost of connecting variable renewables to the local backbone transmission system.

Major existing electricity sector policies are incorporated into ReEDS, including state RPS requirements, production and investment tax credits (including phase-outs), and air pollution policies and regulations (CSAPR, CAIR, MATS, AB-32, RGGI). The Clean Power Plan is not included based on ongoing review and proposal to repeal.

The ReEDS model version used for this analysis is similar to that used for the NREL 2016 Standard Scenarios report, which is documented in detail in Eurek et al. (2016) (Cole et al., 2016b; Eurek et al., 2016).[2] Key data and assumptions are described in the following section.

2.1.1.2. Data. Many key input data for ReEDS are derived from AEO 2016, the 2016 NREL Annual Technology Baseline (ATB16), and the ABB Velocity Suite (EIA, 2016; Cole et al., 2016a; ABB, 2017).

Performance and nominal capital and OM costs for fossil and nuclear technologies are taken from AEO 2016, while ATB16 Mid Case provides performance and nominal cost information for renewables (EIA, 2016; Cole et al., 2016a). Fig. 2 shows LCOE trajectories for three renewable technologies. For land-based wind, these data imply a 19% reduction in pre-tax credit levelized cost of electricity (LCOE) by 2050 from base values of $46–224/MWh (in 2016) depending on the wind resource category. Offshore wind LCOE is assumed to fall 35% in the same time frame but from higher initial values of $159–219/MWh. ATB16 Mid Case utility PV costs fall 53% in 2016–2050, with representative 2016 LCOE values of $77/MWh, $107/MWh, and $153/MWh for 28%, 20%, and 14% capacity factors, respectively.

Unlike typical standalone ReEDS analysis, which uses AEO data for electricity demand growth, coal prices, and natural gas prices, the linked model determines these parameters endogenously as described below. Uranium fuel prices are exogenously defined using AEO 2016 (EIA, 2016).

Capacity retirements are a key driver to electricity system needs. ReEDS uses exogenously specified retirements from the ABB Velocity Suite, which includes announced retirements and lifetime-based retirements (ABB, 2017). Absent an announced retirement date, the database assumes coal units under 100 MW operate for 65 years, coal units above 100 MW for 75 years, and natural gas-based units for 55 years. Nuclear units without announced retirement dates are assumed to receive a single service life extension approval and thus operate for 60 years. Lifetimes are also specified as 24 years for wind capacity and 30 years for solar. Existing and new hydropower is assumed to remain operating through 2050. In addition to announced and lifetime retirements, coal capacity is retired endogenously based on utilization rate. The required utilization rate starts at 1% in 2020 and increases to a maximum of 50% in 2040, which accelerates coal retirements by eliminating enough capacity in each year from least-to-most efficient for the remaining capacity to have operated at the utilization rate threshold (Eurek et al., 2016). This construct is a proxy for retirement decisions based on long-term fixed and variable operating cost considerations.

A complete description of the ReEDS model and data can be found in model documentation and the ATB (Eurek et al., 2016; Cole et al., 2016a).

2.1.2. U.S. Regional Energy Policy (USREP) model

2.1.2.1. Model structure. USREP is a top-down CGE model characterizing six regions within the United States (see Fig. 1) and fifteen internationally, along with multiple sectors, production factors, and household income classes (Table 1). International regions represent either single countries or multi-country regions.

Five energy sectors and six non-energy composite sectors are identified in USREP. This sectoral representation does not explicitly differentiate the wind industry outside of its technology representation within the ReEDS electricity sector model. While doing so could be useful to understand non-electricity impacts and characteristics specific to the wind industry, the current representation still allows a rich discussion of electric sector and economy-wide effects. Defining additional sectors in USREP for the wind and solar industries remains the subject of potential future work.

Demand is distinguished between households, the government, and corporate entities. Primary production factors are separated into capital, labor, and several resource factors. Firms are assumed to maximize profits and sell goods at prices equal to marginal costs in perfectly competitive markets. Substitution possibilities in production are characterized using nested constant elasticity of substitution (CES) functions.

U.S. households are differentiated using 9 income classes distinguished by expenditure patterns and income sources, allowing for distributional impacts to be examined in detail. Each household type maximizes utility with preferences represented by a CES utility function that combines consumer goods, investment, and leisure under a constraint that consumption must equal income. Labor supply is endogenously determined by the household choice between leisure and labor and is calibrated to generate a specific supply elasticity of labor. Labor is perfectly mobile between sectors within regions, but immobile across regions.

While capital ownership is differentiated across income classes, new malleable capital is assumed to be perfectly mobile across U.S. sectors and regions, meaning that capital ownership is not geographically correlated with the location of capital returns. This assumption is relevant to potential capital investment in wind energy production capacity, which must be located in regions with favorable wind resources but is not limited by regional investment capacity. Returns to this investment (as well as other rents from the electricity sector) are pooled nationally and redistributed to households according to existing capital ownership patterns across regions and income classes. The implication is that regional economic impacts are not necessarily correlated with regional wind deployment as will be discussed in greater detail in Section 3.5. In each region, a single government entity represents local, state, and federal government activities. The government purchases goods and services, transfers incomes, and raises revenue through taxes. The model explicitly tracks the bilateral trade of both intermediate and final goods across all sub-national and international regions. For non-U.S. regions, there is a static representation of policy; thus, no explicit environmental policies and emissions reductions goals are modeled. The implications of this assumption are discussed below.

With the exception of crude oil, which is modeled as a homogeneous commodity, goods are assumed to be differentiated following the Armington assumption. The model differentiates goods by local (within-domestic region), domestic (within the U.S.), and international origin in a three-level nesting structure, which is calibrated to replicate a domestic border effect in which goods from within the United States are assumed to be closer substitutes to each other than goods from an international origin.

[2] Due to the development challenges inherent in linking the ReEDS and USREP models, a slightly earlier ReEDS version is used for this work. Key differences include: (1) the updated hydropower formulation developed for the *Hydropower Vision* (DOE, 2016) is not incorporated, (2) an older representation of state RPS constraints is used, and (3) historical calibration for 2010–2014 does not include improvements to better match generation and CO_2 emissions data. These differences somewhat reduce accuracy of the electric sector solution relative to the Standard Scenarios report (Cole et al., 2016b), particularly in the near term, but they should not substantially influence comparisons across scenarios and the broader economic implications that are the primary focus of this work.

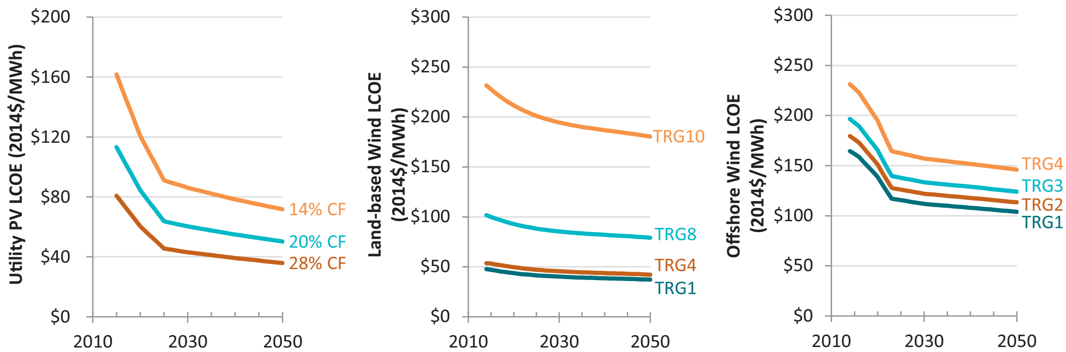

Fig. 2. Base values for levelized cost of electricity for wind and utility PV technologies in ReEDS before any endogenous capital or labor price-driven changes from USREP. CF = capacity factor, and TRG = techno-resource group, which are wind resource categories characterized by wind speed and turbine design considerations for that wind speed. There are 10 TRGs each for land-based and offshore wind in ReEDS, with those shown providing the range of LCOE values (Cole et al., 2016a).[3,4]

Table 1
USREP model characteristics.

Regions	U.S. household income classes ($1000 of annual income)	Sectors	Production factors
United States	<10	Energy	Capital
Northeast	10–15	Coal	Labor
East Central	15–25	Natural Gas	Resources
Southeast	25–30	Crude Oil	Coal
North Central	30–50	Refined Oil	Natural gas
South Central	50–75	Electricity (using ReEDS)	Crude oil
West	75–100		Land
European Union	100–150	Non-Energy	
Japan	>150	Manufacturing	
Brazil		Services	
China		Agriculture	
India		Transportation	
Russia		Energy-intensive products	
Mexico		Other	
Canada			
Australia & New Zealand		Final Demand	
Middle East		Households	
Africa		Government	
Rest of Latin America		Investment	
Rest of Europe and Central Asia			
Dynamic Asia (Hong Kong, Philippines, Malaysia, Taiwan, Singapore, Indonesia)			
Rest of East Asia			

Like ReEDS, USREP solves sequentially in 2-year solve intervals, though its base year of 2006 means that it is run independently before linked operation begins in 2010. This recursive-dynamic approach implies myopic decisions without foresight. Between each time period, capital is depreciated, and a fraction of previously installed malleable capital becomes non-malleable capital. This characteristic limits the capacity of the model to re-assign capital from one sector to another due to policy or technology shocks. These adjustment costs generate path-dependency such that the recursive-dynamic equilibrium is not necessarily inter-temporally optimal.

Within periods, malleable capital is supplied with a positive elasticity that is based on the household decision to invest in market or residential capital. Energy resources are also assumed to be depleted over time, which produces a monotonic rise in production costs. Though commodity markets often do not exhibit smooth behavior due to technological change and geopolitical factors, these real-world influences are not easily incorporated into a CGE framework. Technological change is however included through a rate of autonomous energy efficiency improvement (AEEI), which represents non-price induced improvements in energy efficiency.

2.1.2.2. Data. The USREP model is calibrated to a comprehensive energy-economy dataset created from a number of sources. The social accounting matrix (SAM) is based on data from four sources:

1. The Global Trade Analysis Project (GTAP): production and input-output tables for international regions, international trade, and trade elasticities (Badri and Walmsley, 2008),
2. The Impact Analysis for Planning (IMPLAN) data set: production and input-output tables for US states, and capital demand and transfer data (IMPLAN, 2008),
3. The U.S. Census Bureau: employment data as well as trade between US regions and international regions (US Census Bureau, 2010), and
4. The EIA: energy demand, production, and trade in U.S. regions from the State Energy Data System (USEIA, 2009).

U.S. GDP growth, energy demand, CO_2 emissions, coal prices, and natural gas prices are calibrated to closely match the AEO16 Reference Case forecasts in the linked model by adjusting reference input assumptions in both models. This calibration is performed by making adjustments to available energy reserves (for fossil fuel prices), AEEI (for

[3] Land-based TRG10 is not generally considered practical for economic deployment but is shown to demonstrate the range of input data.

[4] Offshore wind is subdivided such that TRG1–4 are shallow depth monopole turbines (0–30 m), TRG5–7 are mid-depth jacket designs (31–60 m), and TRG8–10 are deep water floating platforms (61–700 m). Capital and operating costs are identical within subcategories and in ascending order with depth subcategory. However, capacity factor is in descending order only across TRGs within a subcategory, so low capacity factors result in TRG4 having the highest LCOE.

emissions and energy demand), and productivity (for GDP growth). Population growth is exogenously defined using data from the United Nations and U.S. Census Bureau.

2.1.3. Linked model operation

Linked operation begins with an initial benchmarking step during the first year of model iteration, 2010. As described in Rausch and Mowers (2014), this calibration step ensures that the price and quantity of electricity sector inputs and outputs in ReEDS are consistent with the electricity sector in the SAM underlying USREP. USREP is first run independently for 2010, then the resulting electricity demand, electricity price, and fossil fuel prices are imposed on ReEDS with its default input cost data. The subsequent ReEDS solution then supplies expenditures for electric sector capital, labor, and fuel that can be compared with the previous USREP solution. Differences between the ReEDS and USREP solutions then establish static calibration parameters used to translate between ReEDS and USREP results throughout the simulation. These offset parameters do not fully rebalance the SAM based on ReEDS results, but they approximate doing so in a way that enables ReEDS results to be used consistently with the USREP data and model structure. After benchmarking establishes parameter conversions between models, subsequent parameter exchange is defined as indices such that growth rates in prices and quantities are required to converge.

A major difference between models is that ReEDS simulates busbar generation and load (at the substation level), where USREP represents end-use electricity consumption. Thus, the lack of a transmission and distribution representation in ReEDS beyond the inter-BA transmission system requires electric sector parameters to be converted between busbar and end-use to enable model communication. For electricity quantities, this conversion is done simply using the standard ReEDS assumption for distribution losses—5.3%. Converting electricity prices requires an estimate of the price component attributable to intra-BA transmission and distribution. In reality, such prices can change over time and space with the makeup of the generation and transmission system, and characterizing this dynamism is not possible within the existing modeling framework. As an approximation, the region-specific difference between ReEDS and USREP electricity prices in the 2010 benchmarking iteration is used to estimate the intra-BA transmission and distribution price component, and these quantities are used to convert between ReEDS and USREP electricity prices for the remainder of the simulation.

After the initial benchmarking procedure, USREP and ReEDS iterate until convergence is achieved before continuing to the next solve year. As in Rausch and Mowers (2014), total U.S. electricity demand is used as the convergence parameter. We verify ex-post that convergence in other variables such as input prices is also achieved. Given the relatively small size of the electricity sector within the whole economy in USREP, convergence is usually reached after a small number of iterations (a result already documented by other top-down bottom-up coupling exercises). The procedure is as follows.

1. Solve USREP.
2. Pass USREP equilibrium outcomes to ReEDS, including price indices for capital; wage and service price indices for OM costs; fuel prices for coal and gas; and the electricity price, quantity, and the local slope of the electricity demand curve around the equilibrium outcome.
3. Define ReEDS parameters using USREP outcomes.
   a. Scale capital and OM costs using capital and OM price indices.
   b. Use USREP coal and gas price indices to scale coal and gas costs.
   c. Use USREP electric sector parameters to construct a piecewise linear electricity demand curve used in ReEDS constraints and objective.
4. Solve ReEDS.
5. Pass ReEDS outcomes to USREP, including capital and OM expenditures, electric sector investment demand, fuel use and expenditures, and electricity demand.
6. Define USREP parameters using ReEDS outcomes.
   a. Use ReEDS electricity demand as the new exogenous equilibrium electricity production in USREP.
   b. Use ReEDS fuel, capital, and OM costs to define electric sector investment demand and commodity and factor usage in USREP.
7. Check convergence of U.S. electricity demand and return to Step 1 if convergence is not achieved.[5]

The piecewise linear electricity demand curve generated for ReEDS using USREP electricity market results is substituted in ReEDS constraints in place of demand that would be exogenously applied when running standalone ReEDS. Affected constraints include the supply-demand balance and planning reserve requirements. The demand curve is also incorporated into the ReEDS objective function to represent consumer surplus. The electric sector costs represent producer surplus, allowing the ReEDS objective to be converted from a cost minimization to a surplus maximization so that ReEDS can approximate equilibrium electricity demand and price. While sectors in USREP are assumed to be perfectly competitive with zero profits, ReEDS has no such restriction so effectively allows price markups in the electricity sector. Corresponding profits are combined with other returns to electricity capital and allocated to households in USREP based on observed economy-wide patterns of capital ownership (both regionally and across income classes).

2.2. Key output metrics

The character of electric sector capacity and generation expansion are similar to the scenarios discussed in the *Wind Vision* report, but incorporating elastic demand and multisectoral impacts on commodity prices warrants a re-exploration of national electric sector output from ReEDS. The influence of other sectors on the electricity system can also yield differences in environmental outcomes such as CO_2 emissions.

The ability to study behavior of the broader U.S. economy, however, is the strength of this modeling approach. We use GDP and equivalent variation as measures of overall economic performance, and we report investment, capital and labor returns, and wages to describe how production sectors and households interact. As USREP also tracks outcomes by household income class and region, it allows an exploration of distributional and regional differences in economic performance.

3. Results

3.1. Electric sector supply, demand, and prices

Generation by technology over time is shown in Fig. 3, and Fig. 4 highlights the differences in both generation and capacity between the *No New Wind* and *Study Scenarios* relative to *Business-as-Usual*. Electric sector evolution is largely similar to the corresponding scenarios in the *Wind Vision* report, though differences in model structure and updated data cause modest deviations.

In the *No New Wind Scenario*, wind capacity is fixed at 2016 levels by design. Energy and capacity needs arising from growing demand and retiring coal and nuclear facilities are thus met primarily by growth in natural gas combined cycle plants (NG-CC) and solar photovoltaics (PV).

The *Business-as-Usual Scenario* is nearly identical to *No New Wind* through 2030, with little incremental increase in wind deployment in that time. However, 2050 wind capacity in *Business-as-Usual* is 179 GW greater than *No New Wind* (for a total of 257 GW) and provides 24% of end-use electricity demand as compared to 9% for *No New Wind*. Only land-based wind is built in the *Business-as-Usual*. Additional wind energy generation largely displaces NG-CC and PV along with some coal-based electricity. NG-CC and PV *capacity* is also displaced by

[5] Throughout this analysis, the convergence criterion is a relative fractional change of 10^{-6} between iterations.

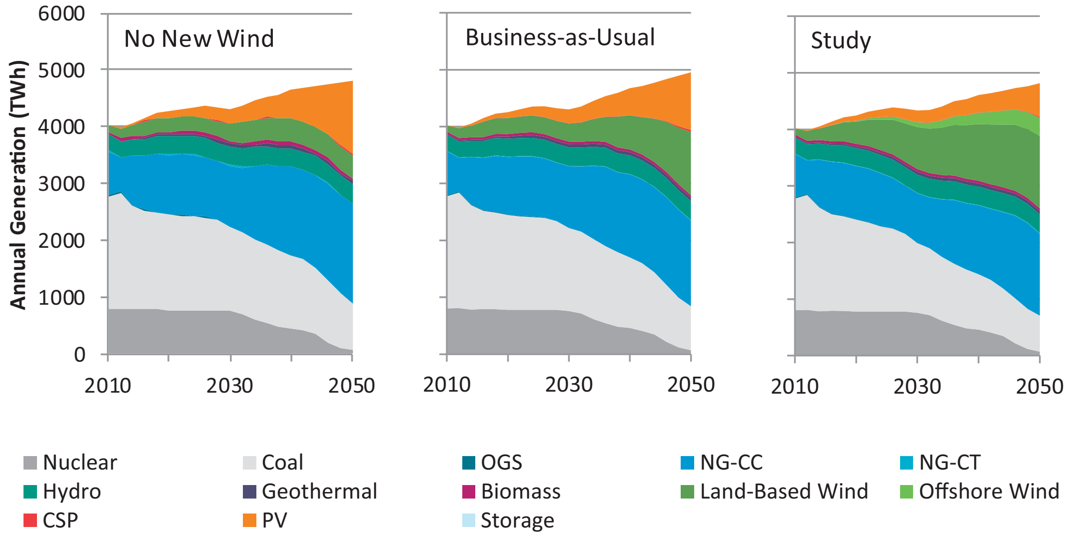

Fig. 3. Electricity generation by technology shows long-term electric sector behavior in each scenario.

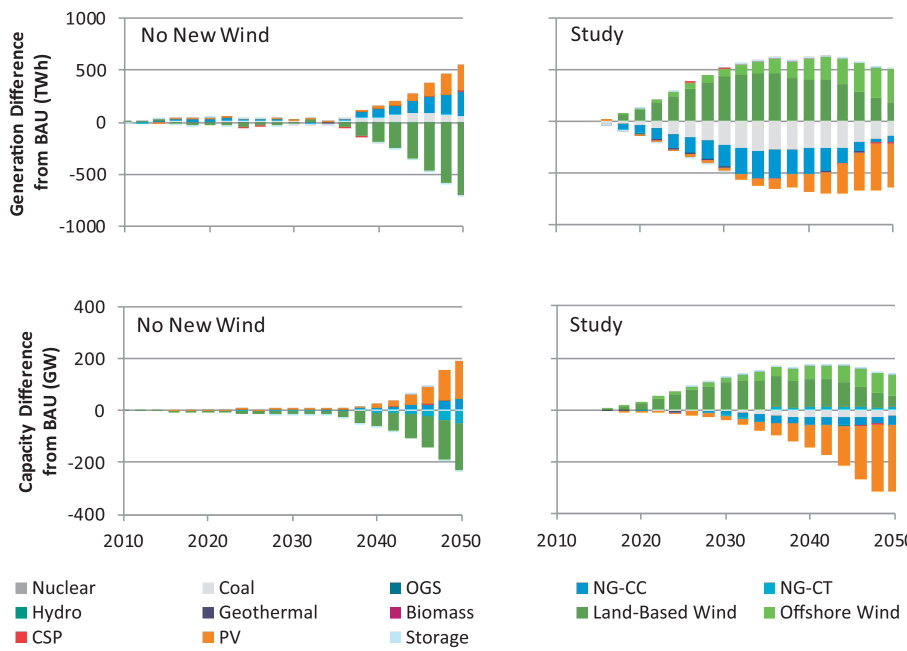

Fig. 4. Differences in electricity generation (top panel) and capacity (bottom panel) by technology relative to the *Business-as-Usual Scenario* show differences in electric sector expansion across scenarios.

land-based wind, and additional natural gas combustion turbine (NG-CT) capacity is also built in the *Business-as-Usual* to provide reserve services.

Wind deployment is prescribed throughout the solve period in the *Study Scenario*, resulting in far greater wind energy and capacity than both other scenarios in the near and long term. The *Study Scenario* reaches 217 GW total wind capacity by 2030 and 382 GW by 2050, with 80 GW of 2050 wind capacity from offshore wind construction (which is also by design).[6] As a result, *Study* has the least generation from NG-CC, PV, and coal and the most additional NG-CT capacity to provide reserves.

The linked model represents fuel supply and demand across all economic sectors, so changes in the electricity generation mix can influence overall fuel markets, notably those for coal and natural gas. Fig. 5 displays electric sector coal and natural gas usage along with national average prices of those commodities weighted by regional usage. Relative to *Business-as-Usual*, lower coal or gas usage by the electric sector in the *Study Scenario* corresponds to lower coal and gas prices, while the opposite is true for *No New Wind*. Underlying assumptions regarding fossil fuel resource supply are the same for all scenarios, so reducing fossil fuel demand by the electric sector tends to reduce price because the electric sector is an important consumer of these fuels. These price trends are not negated by rebound effects or fuel use in other sectors, which underscores the importance of the electric sector to fossil fuel markets.

Relative to *Business-as-Usual*, 2050 electric sector coal usage is 18% lower in the *Study Scenario*, producing prices that are 5% lower. In the

[6] The *Study Scenario* wind deployment differs from the 404 GW reported in the *Wind Vision* report due to ReEDS model updates and the multisectoral interactions represented in ReEDS-USREP. Major differences include lower PV technology costs and lower fossil fuel prices, particularly for natural gas.

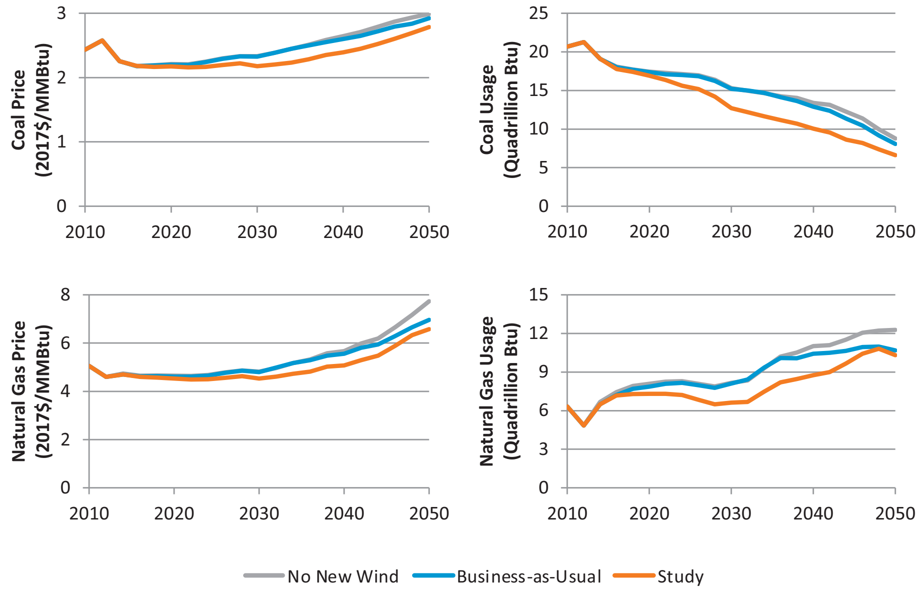

Fig. 5. Electric sector coal and natural gas usage and national average prices reveal differences in fossil fuel markets across scenarios. Average prices are weighted by regional usage.

No New Wind scenario, coal usage is 9% higher and prices 2% higher. Electric sector gas usage relative to *Business-as-Usual* in 2050 is 15% higher in *No New Wind* and 3% lower in the *Study Scenario*, resulting in prices that are respectively 11% higher and 6% lower. Coal prices are relatively less affected by changes in demand from the electric sector than gas prices because total coal sector output continues to grow after 2016, largely due to growth in coal exports. Total gas sector output, on the other hand, trends closely with gas usage in the electric sector.

ReEDS-USREP represents price-responsive electricity demand, which is not the case in the standalone version of ReEDS employed for the *Wind Vision* report, in which demand is exogenously prescribed. As a result, the linked model allows us to explore how the *Wind Vision* scenarios affect electricity markets themselves. In particular, endogenous demand means that higher costs or prices are moderated by lower demand. Fig. 6 demonstrates these effects, plotting national electricity demand and the national average electricity price for each scenario. In the coal and natural gas markets, additional wind generation reduces demand for these commodities by the electric sector, with reduced demand leading to lower prices. In the electricity market, however, exogenous changes in wind deployment act as a supply-side increase in costs, so equilibrium electricity demand falls while price rises. This effect is true both for the scenario with additional wind prescriptions and for the scenario preventing wind penetration: prescribing deployment of otherwise non-competitive wind capacity results in higher-cost generation and prohibiting otherwise competitive wind capacity growth in *No New Wind* necessitates higher-cost generation technologies. In both cases, increases in electricity prices thus also suppress electricity demand in a similar fashion.

All three scenarios exhibit nearly-identical electricity demand and price pathways through 2030. Growth is strong initially but flattens and even falls slightly before and around 2030 before recovering in later years. This behavior is attributed to the relatively modest construction of new capacity in the first half of the study period, followed by a shift in sectoral needs towards new capacity in the latter decades. Initially, the modeled electricity system has excess capacity, allowing demand growth to be sustained as relatively inexpensive fuel switching to natural gas and renewables occurs in response to coal retirements and renewable incentive policies. Under this regime, electricity system energy and reserves requirements are met with relatively little capital investment. However, capacity retirements after 2030 create a stronger need for new capital investment to satisfy capacity reserves constraints, and electric sector consumers must adjust to price impacts of this need before resuming demand growth. During this adjustment period, escalating electricity prices cause demand to temporarily stagnate.

Beyond 2030, the ability to deploy wind in *Business-as-Usual* allows for lower electricity prices and stronger demand growth. Prescribing wind growth beyond *Business-as-Usual* leads to slightly higher prices and lower electricity demand than *No New Wind* in much of the 2030s and some of the 2040s, but electricity market behavior converges with *No New Wind* in 2050. By 2050, electricity prices in the *Business-as-Usual* are 5–6% lower than the other scenarios, while electricity demand is approximately 3% higher. Differences between the *Study* and *No*

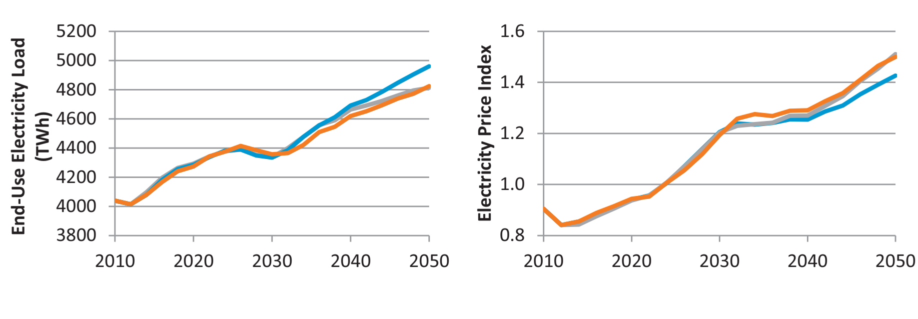

Fig. 6. Scenario differences in electricity market behavior are apparent in national electricity demand and price.

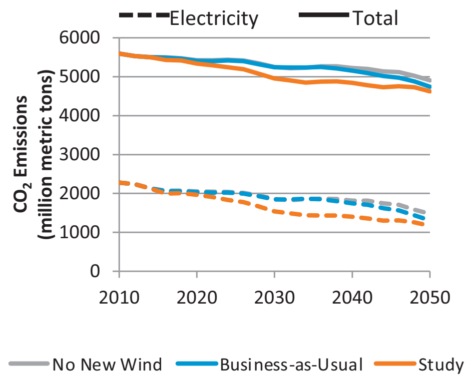

Fig. 7. National CO_2 emissions in the electric sector (dashed lines) and all sectors combined (solid lines) reflect differences in electric sector expansion.

New Wind are <1% even though the underlying electricity mix is very different.

3.2. CO_2 emissions

Fig. 7 plots CO_2 emissions in the electric sector as well as economy-wide U.S. CO_2 emissions. As stated in Section 2.1.1, no U.S. CO_2 mitigation policies are assumed in ReEDS beyond currently enacted local CO_2 limits, renewable energy tax credits, and RPS requirements, and no CO_2 mitigation policies outside of the electricity sector are implemented in USREP. Thus, CO_2 emissions in the electric sector are driven by changes in the electricity generation mix, with higher wind deployment corresponding to lower CO_2. Scenario assumptions do not differ beyond those in the electric sector, so total U.S. CO_2 emissions broadly follow the same trend as electric sector CO_2 emissions. Despite the lack of new CO_2 mitigation policies in any scenario, emissions still fall over time as coal-based capacity retires and demand growth, which is moderated by assumed energy efficiency improvements, is increasingly met by NG-CC, wind, and PV.

Fig. 8 plots the absolute difference in electric sector and total emissions in the *No New Wind* and *Study Scenarios* relative to *Business-as-Usual*. With no new wind deployment, emissions are approximately 160 million tCO_2 higher in 2050, an increase of 12% in the electric sector and 3% in total. The change in total CO_2 and electric sector CO_2 is nearly identical, suggesting that the CO_2 reductions from wind deployed in *Business-as-Usual* occur with minimal emissions leakage to other sectors.

Additional wind constructed in the *Study Scenario* yields substantial reductions in total U.S. emissions relative to *Business-as-Usual*, reaching nearly 400 million tCO_2 in the 2030s. By 2050, the *Study Scenario* emits 11% less CO_2 in the electric sector and 3% less across the U.S. economy. CO_2 emissions reductions in *Study* are somewhat greater in the electric sector than the overall economy, but emissions leakage remains relatively low at 7–9% over the 2030–2050 period. Overall, the potential emissions reductions afforded by wind deployment are robust across the rest of the economy.

3.3. Impacts on the U.S. economy

We use total equivalent variation (EV) as a measure of household welfare. EV relative to *Business-as-Usual* is plotted in Fig. 9 along with per capita gross domestic product (GDP).[7] By these measures, wind deployment is largely beneficial. Welfare and GDP in *No New Wind* are nearly the same as *Business-as-Usual* through 2030 when *Business-as-Usual* wind deployment is minimal, but *No New Wind* values are

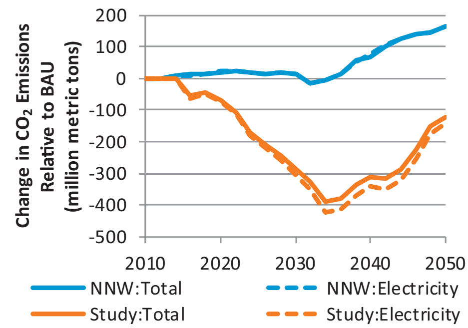

Fig. 8. The change in total and electric sector CO_2 emissions relative to the *Business-as-Usual Scenario* demonstrates some leakage in the *Study Scenario*.

considerably lower after *Business-as-Usual* wind investment accelerates, reaching a relative difference of 0.10–0.11% by 2050. Additional wind deployment in the *Study Scenario* achieves additional welfare and GDP benefits throughout most of the study period: welfare and GDP are higher than *Business-as-Usual* by the late 2020s through the 2030s and 2040s, though relative improvements stagnate and fall slightly below *Business-as-Usual* by the late 2040s. The relative change in per capita GDP is similar to EV for both scenarios, but the EV increase outpaces GDP in the *Study Scenario* beginning in the mid-2030s, as the returns to capital, which lead to more consumption by households, eventually outpace investment as a determinant of GDP. Given the relatively small share of the electricity sector within total GDP and welfare, differences in wind deployment lead to small *relative* changes in economy-wide outcomes. Nevertheless, in *absolute* terms, the 0.06% increase in 2030 EV in the *Study Scenario* equates to approximately $14 billion in that year ($38 per capita), and the observed 0.06% increase in 2050 GDP in *Study* equates to $17 billion ($48 per capita). In 2050, single-year reductions in EV and GDP amount to $6 billion and $19 billion for *Study* but are much higher at $39 billion and $43 billion with *No New Wind*.

The improvements in welfare and GDP with higher wind deployment arise from two main drivers: (1) a reduction in the price of consumption, and (2) increased returns to electric sector capital raising household incomes. Cost-effective wind deployment can reduce electricity prices, which leads to reductions in the price of goods that are electricity-intensive in production, which in turn increases welfare by increasing household purchasing power. Electric sector investment related to additional wind deployment can increase the demand for both capital and labor, which can improve the welfare of households that provide these production factors but can also have a negative effect by reducing capital and labor available to other sectors. GDP and welfare in *Study* are below that of *Business-as-Usual* in the 2040s because prices

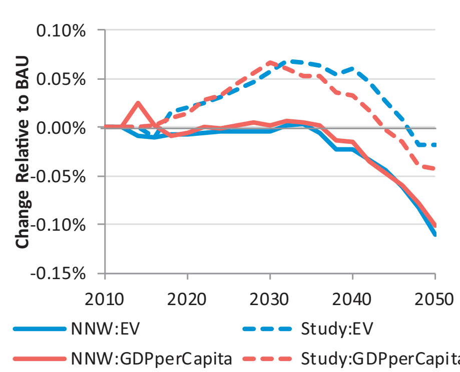

Fig. 9. Change relative to *Business-as-Usual* of equivalent variation and per capita GDP reveal economic benefits for both scenarios.

[7] GDP is calculated as the sum of consumption, government expenditures, investment, and net exports.

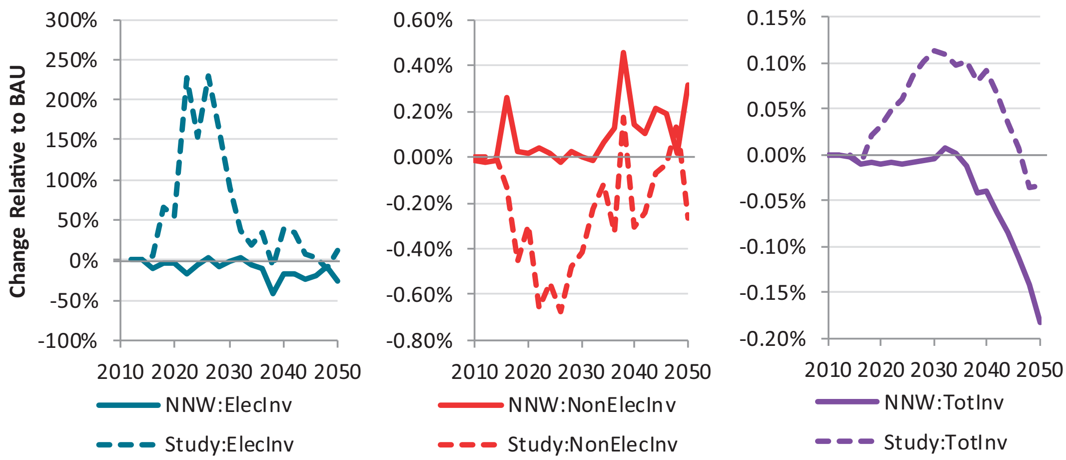

Fig. 10. Change relative to *Business-as-Usual* of investment in the electricity sector (left), all non-electricity sectors (middle), and total investment (right) shows higher overall investment driven by electricity sector investment, particularly in the *Study Scenario*. Represented here is the value of investment (price × quantity).

of consumption are higher, offsetting the effect of higher electric sector capital returns.

Investment, capital and labor returns, and wage effects are reflected in Figs. 10, 11, and 12. Investment (Fig. 10) and returns on capital investment (Fig. 11) are shown relative to *Business-as-Usual* for the electricity sector only, all non-electricity sectors combined, and in total. Note that the scales for the electric sector are much larger because scenario differences are largest in the electric sector, and the combination of all other sectors make up a much larger portion of the economy.

No New Wind electric sector investment is slightly lower than *Business-as-Usual* in some years before 2030, but these differences translate to little overall change in total investment in that time frame. The wind deployed in the *Business-as-Usual* scenario causes a slight shift in investment towards the electric sector, which leads to a slight increase in total capital returns despite reductions in non-electric sector capital returns. Beyond 2030, lower GDP in *No New Wind* is attributed to both higher electricity prices (Fig. 6) and reduced investment, with the diminished returns to this investment also reducing incomes and thus welfare. Lower electric sector investment results in lower total investment beyond the mid-2030s, which decreases capital returns along with welfare and GDP.

Reduced investment in *No New Wind* also drives lower wages beyond the mid-2030s (Fig. 12), but total returns to labor (also Fig. 12) are not substantially different from *Business-as-Usual*. Wind penetration in *Business-as-Usual* could lead to a greater increase in labor returns, and lower returns to capital, if we differentiated labor markets within the wind industry and assumed wind to be more labor-intensive than fossil generating sources, which has been suggested by some of the literature (IRENA, 2017; Duscha et al., 2014, 2016). The relationship between technology choice and the relative demand for labor versus capital is complex. The labor requirements of each generation technology vary over its life cycle. Some of these differences are captured by our model; some are not. The ReEDS model explicitly captures technology-specific differences in OM costs, which include the OM contribution towards total labor costs. USREP captures differences in the upstream labor intensity of other inputs, including the labor required to produce fossil fuels. It also captures the labor market impacts of increased investment. However, labor-investment impacts are not differentiated by sector or electricity generation technology. If the manufacturing and installation of wind turbines is significantly more labor-intensive than other technologies, we might be underestimating impacts of wind deployment on the labor market. However, attributing a higher labor-intensity to wind is unlikely to substantially affect our estimates of overall economic impacts as it would mostly drive a re-allocation from capital to labor returns. Further exploration of technology-specific labor intensity is a worthwhile topic for future work.

In the *Study Scenario*, electricity prices are also higher than in *Business-as-Usual*, putting downward pressure on welfare. The main driver of welfare changes, however, is the additional investment and ensuing returns to capital. Total investment is up to 0.11% higher in the *Study* scenario than in *Business-as-Usual* for all years beyond 2016, which amounts to a maximum of $4.6 billion per year. Wind

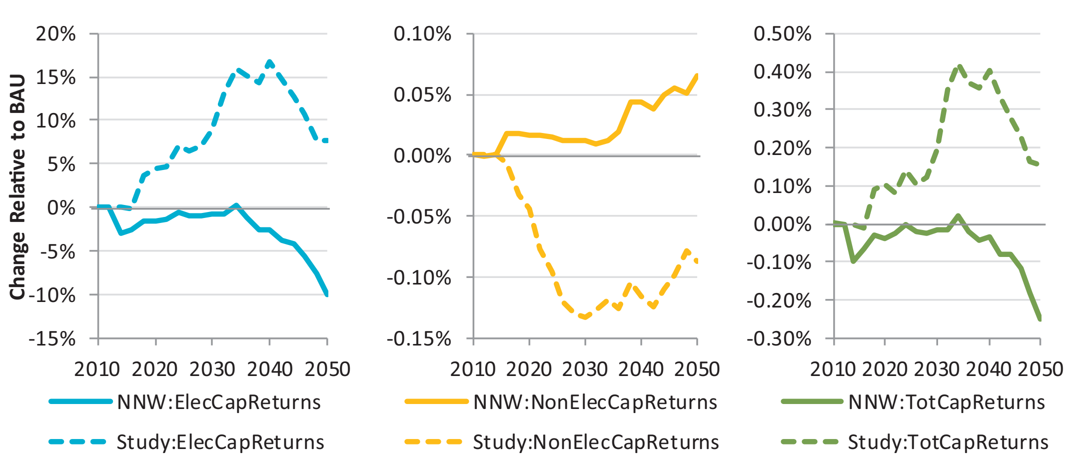

Fig. 11. Change relative to *Business-as-Usual* of returns to electricity sector capital (left), non-electricity sector capital (middle), and economy-wide returns to capital (right). These help explain economic outcomes. Represented here are returns to capital (rate of return × quantity).

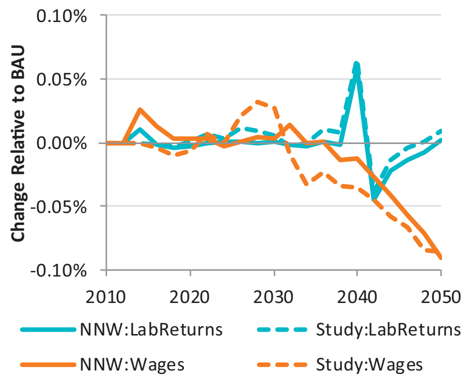

Fig. 12. Change relative to *Business-as-Usual* of wages and labor returns (the wage bill) reveal only small effects on the labor market.

capacity deployment leads to 60–230% higher electric sector investment than *Business-as-Usual* in the 2020s and 20% more on average in 2030–2050. Though investment and capital returns in other sectors fall, the net effect drives an increase in total capital returns throughout most of the study period, leading to GDP and welfare improvements until the 2040s. Subsequently, GDP and welfare fall slightly below *Business-as-Usual* as the prescribed wind deployment in *Study* becomes more expensive and thus less beneficial to the economy on the whole.

As with *No New Wind*, returns to labor in *Study* are similar to *Business-as-Usual*, though again this result might differ if labor-intensity differences between generating technologies were considered. Wage impacts follow trends in electricity prices relative *Business-as-Usual*, with wages being slightly lower in both the *Study* and *No New Wind Scenarios*; however, changes are all within +0.03/−0.09%.

The long-term value of each economic metric is summarized in Fig. 13, which shows net present value (NPV) of each metric relative to *Business-as-Usual* for 2017–2030 and 2017–2050 using a 3% social discount rate consistent with U.S. Office of Management and Budget guidelines for long-term cost-benefit analyses. The *Business-as-Usual* and *No New Wind* are very similar through 2030, so differences are small, though slight deviations in investment lead to lower net present value under *No New Wind* for capital returns (0.02%) investment (0.01%), and EV (0.01%). Additional pre-2030 wind deployment in *Study*, on the other hand, yields a $88 billion (0.03%) increase in GDP facilitated by higher capital returns, EV, and investment.

Over the 34-year period between 2017 and 2050, differences between scenarios become more apparent. The economic disbenefits from prohibiting wind expansion under *No New Wind* occur in later years, so they are discounted more heavily than the nearer-term improvements in the *Study Scenario*, leading to reductions in GDP ($111 billion) and EV ($110 billion) that are smaller than improvements in the *Study Scenario*. Changes in *No New Wind* are caused by lower investment ($32 billion, 0.04%) and returns to capital ($90 billion, 0.05%). Though wage impacts are important to welfare trends, wages fall primarily in the 2040s, so discounting makes these changes appear small compared to other metrics.

Persistent investment in wind technologies in the *Study Scenario* over 2017–2050 achieves a notable increase in GDP ($150 billion, 0.02%) and EV ($192 billion, 0.04%) which is largely attributed to changes in investment ($54 billion, 0.06%) and capital returns from increased investment ($398 billion, 0.22%) relative to the *Business-as-Usual Scenario*. These results demonstrate the potential economic benefits achievable by stimulating wind investment beyond the *Business-as-Usual*, even under reference technology cost and performance assumptions.

Our results thus indicate that greater electric sector investment in wind generating capacity can be beneficial to the national economy. However, lack of technology differentiation outside of the electricity sector prevents us from concluding that wind capacity deployment would impact the economy differently from other technologies. Beyond that, several underlying assumptions warrant discussion.

First, generation technology capital and operating costs are exogenously defined in ReEDS using market projections from the EIA and NREL; thus, they do not incorporate learning effects and are not affected by modeled deployment (Cole et al., 2016a; EIA, 2016). If additional wind technology cost reductions were induced by the prescribed wind deployment in the *Study Scenario*, reduced capital needs could negate some welfare gains attributed to higher capital returns. This outcome would be offset by lower electricity costs, but the net effect is uncertain.

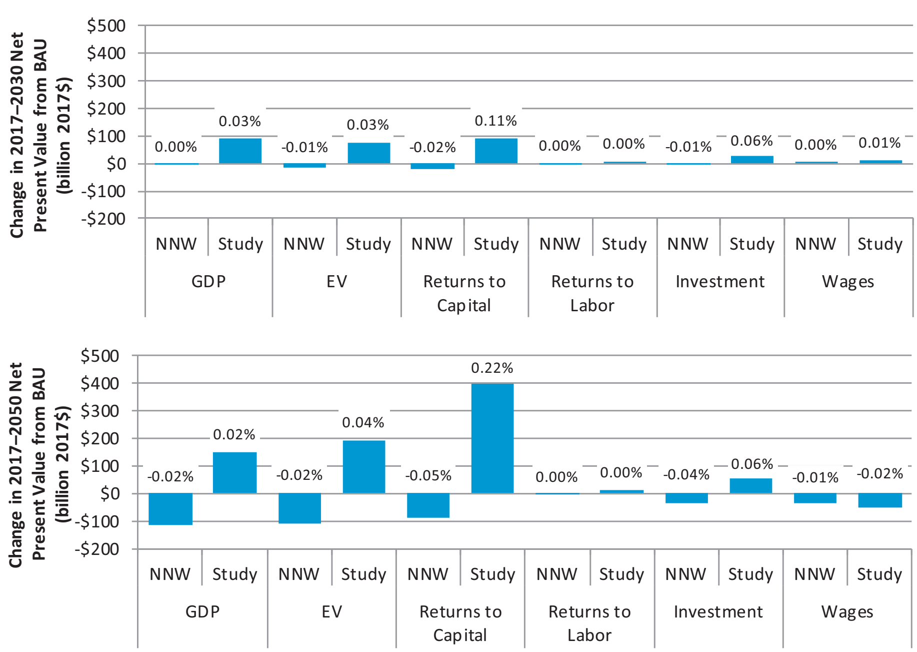

Fig. 13. Change in 2017–2030 and 2017–2050 net present value of economic metrics for the *No New Wind* and *Study Scenarios* from *Business-as-Usual* in billions of dollars, with the percent change relative to *Business-as-Usual* also shown.

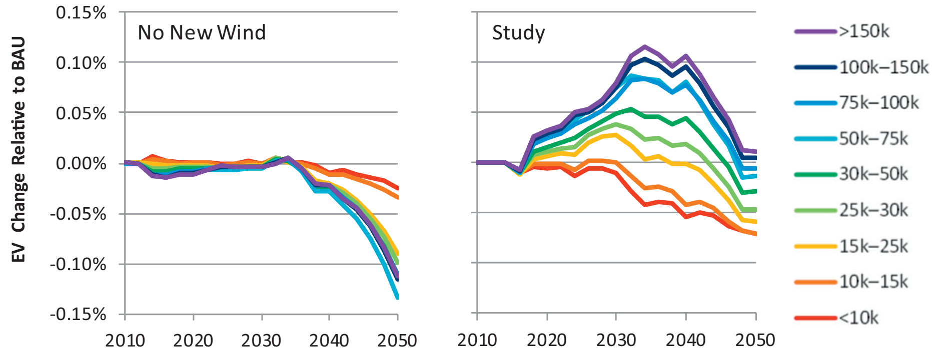

Fig. 14. Change relative to *Business-as-Usual* of equivalent variation by income class reveals regressive behavior in later years in *Business-as-Usual* (by inverting *No New Wind* change relative to *BAU*) and beyond the mid-2020s in the *Study Scenario*.

The value of wind will also depend on the implementation of CO_2 mitigation policies in the United States, which could enhance the positive economic impacts of wind deployment by reducing the cost of wind relative to other technologies. While adding scenarios around technology cost and policies would be interesting future work, we chose to maintain a simple scenario design that better isolates the economic effects of wind capacity growth. Furthermore, the static representation of international environmental policy ignores decarbonization efforts outlined in the Paris Climate Agreement and other stated objectives. If these goals were considered, global market interactions could reduce fossil fuel prices and possibly affect wind technology costs and electric sector capital markets in ways that materially affect results. Additional data and model development is necessary to better characterize these interactions, and international decarbonization policy is an active research topic that could be explored by ReEDS-USREP in the future (Böhringer et al., 2017; Böhringer and Rutherford, 2017).

The robustness of our results is also limited by the inability of the coupled model to optimize the solution intertemporally across the full 2010–2050 time period. Given that the *Study Scenario* prescribes wind deployment that might otherwise not be part of the least-cost generation mix, an intertemporal model might find that the *Study Scenario* has lower welfare than shown here because prescribed wind deployment constrains the electric sector beyond reference conditions. Whether an intertemporally optimized model would be a better approximation of reality than the approach herein, given the well-documented myopic behavior of actual economic agents, is an open question. Real-world economic drivers not represented in the CGE framework could produce different outcomes in response to these future electricity-economy trajectories both in magnitude and direction. An important extension of this point is the observation that national economic outcomes do not change drastically despite the substantial electric sector shift towards wind in the *Study Scenario*, suggesting that the electric sector and economy as a whole is robust to potentially large influxes of renewable electricity.

3.4. Distributional economic impacts

While competitive wind deployment in the *Business-as-Usual* and additional wind deployment in the *Study Scenario* can lead to higher overall economic welfare (measured by EV), the impacts are not distributed evenly across income classes. Fig. 14 plots EV relative to *Business-as-Usual* for households in each of the nine income classes represented in USREP. Distributional differences between *No New Wind* and *Business-as-Usual* are minimal until the 2040s. After that we see that the EV reduction in *No New Wind* harms households at different income levels differently: while each household type sees its welfare decrease, reductions are much greater for income classes above 15k than for the lowest two income classes. Thus, the wind penetration in *Business-as-Usual*, while benefiting all households, is least beneficial for low-income households. The *Study Scenario* is also regressive, with high-income households experiencing larger gains (or smaller losses) than low-income households. While most income classes see positive welfare impacts throughout most of the study period, the lowest income classes (below 15k) actually see a notable welfare reduction relative to *Business-as-Usual* beginning in the mid-2030s; by 2050, their EV is 0.07% lower. Other income classes also have lower EV in *Study* relative to *Business-as-Usual* in the 2040s.[8] These distributional differences arise from the same drivers as the aggregate results discussed in the previous section: changes in the price of goods—including electricity, and changes in household income.

Changes in the prices of goods affect household purchasing power differently depending on their consumption patterns. For instance, households that spend a larger share of their budget on electricity will benefit relatively more from a reduction in the price of electricity. In Fig. 15, we isolate the distributional differences caused by changes in the price of goods by plotting the average price index experienced by households in each income class (relative to *Business-as-Usual*). These are calculated by computing the average changes in the price of the goods each income class consumes, weighting by *Business-as-Usual* expenditure shares by household income class. Note that the model only predicts changes in relative prices, so the overall change in the price index aggregated across households is zero. This measure is thus only useful in describing differential impacts between household types. A positive number in Fig. 15 means that the average price of the goods purchased by households in that income class is lower than the national price index, benefiting that household type.

In the *No New Wind* scenario, electricity prices are very similar to *Business-as-Usual* through the late 2030s, and we see no notable differences in price impacts across income classes. After that, electricity prices rise relative to *Business-as-Usual*, leading to regressive impacts: low-income households that spend more on electricity are harmed by the higher prices caused by excluding cost-effective wind generation from the generation mix. The prices of most goods other than electricity are only marginally affected. The main exceptions are slightly higher coal prices and a more notable increase in natural gas prices. The increase in natural gas prices is the same magnitude as the increase in electricity prices, so this outcome also harms low income households that spend a higher portion of their income on natural gas.

In the *Study Scenario*, electricity prices are briefly lower than Business-as-Usual in the 2020s but become higher after 2030. At that point, changes in purchasing power also become regressive, with all income classes but those earning >75k doing worse than average. By 2050, this distributional effect is weaker than with *No New Wind*, however.

Beyond their impact on consumption prices, differences in wind penetration also affect household welfare through the returns to the factors they own. Households at different income levels derive

[8] However, when comparing *Study* to *No New Wind* (see Supplemental Information), all income classes above 15k see a welfare improvement for the whole study period.

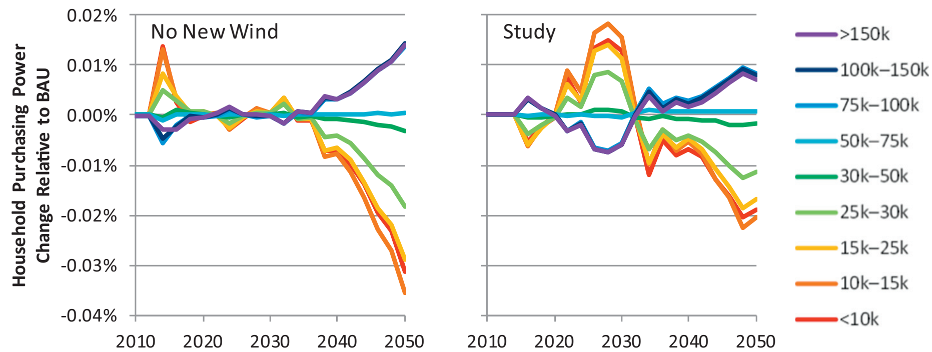

Fig. 15. Change in household purchasing power relative to *Business-as-Usual* as caused by changes in the average price of goods purchased by each household type. All values are normalized by changes in the national average price index and thus sum to zero. A higher value indicates that the household income class experiences a larger than average increase in purchasing power.

their income from different sources, which leads to heterogeneous distributional impacts. Income-driven welfare benefits in both the *Business-as-Usual* and *Study Scenarios* are driven primarily by increased investment and capital returns from the electricity sector (which outweighs smaller reductions in capital returns from other sectors). Increased capital returns disproportionately benefit higher income classes, which own a larger share of capital.

While Fig. 15 has allowed us to identify price effects, comparing it with Fig. 14 demonstrates that income effects dominate price effects in determining distributional impacts. Indeed, the lack of wind construction in *No New Wind* yields differences in purchasing power that are 0.045% *lower* for the lowest income class than for the highest by 2050 (i.e., are regressive), while overall changes in EV, which include both purchasing power and income effects, are 0.11% *higher* (i.e., are progressive). In the *Study Scenario*, both effects are regressive, but purchasing power effects are also smaller in magnitude than income effects. While differentiating the labor-intensity of wind compared to other electricity sources could weaken the impact on capital returns relative to the impact on labor returns, we expect regressive behavior to be robust because low-income households derive large portions of their income from government transfers and profit little from changes in factor returns. Indeed, other analyses using ReEDS-USREP have found that benefits to labor markets in the form of tax rate reductions are—like benefits to capital markets—also regressive (Caron et al., 2018).

3.5. Regional wind generation and investment

Regional differences in the economic impacts of wind deployment can arise from many factors. The local income distribution plays a role; as wind capacity is capital intensive, regions with a greater share of high-income households would disproportionally benefit from capital returns, regardless of where investments are made and wind capacity is deployed. Regional variations in electricity prices can affect local economic outcomes, and the electricity price response to wind generation can depend on the local electricity market structure, the characteristics of new wind capacity, and the composition of the generating fleet providing electricity to the area. There are also local economic benefits to any land owners leasing property for wind turbine construction and operation, and local labor can benefit from jobs created by wind capacity construction and operation.

While USREP represents regional income distributions, investment, labor markets, and electricity prices, it does not capture the detailed business relationships and market structures that influence the local economic impact of wind deployment. In addition, capital markets are assumed to be national so do not reflect region-specific investment. These limitations make it difficult to contextualize the relationship between regional wind deployment and regional welfare as measured by EV. As a result, this section focuses solely on where wind is deployed and the resulting local electric sector investment.

Fig. 16 shows the difference between wind generation in *Business-as-Usual* and wind generation in the *No New Wind* and *Study Scenarios* in 2030 and 2050 for each USREP region. There is little to no difference in wind generation in 2030 for *No New Wind*, but the *Study Scenario* has notably more wind in the Central and West regions. In 2050, additional *Business-as-Usual* wind deployment entails large negative values for *No New Wind*, particularly in the North Central region but also in the South Central and West regions. The *Study Scenario* has more wind generation throughout the United States, but incremental deployment beyond *Business-as-Usual* is most notable in the East Central and West where there is substantial offshore wind deployment.

The corresponding change from *Business-as-Usual* in the net present value of regional electric sector investment appears in Fig. 17 (the top panel showing the 2017–2030 NPV and the bottom panel the 2017–2050 NPV). Trends mirror those of regional generation differences to a large extent but are influenced by investments in solar photovoltaics and natural gas-fired capacity along with wind investments. For example, higher 2017–2050 electric sector investment in the Southeast in *No New Wind* can be attributed to greater solar investment, while wind investment is minimal in *Business-as-Usual* because the Southeast generally has lower quality wind resources than other regions. Regions having a larger difference in NPV between *Study* and *Business-as-Usual* than the difference in 2050 generation have earlier wind deployment. The North Central region is a prime example, where the generation difference between *Business-as-Usual* and *Study* narrows from 2030 to 2050 while the difference in investment does not. Similar behavior in the South Central and West result in relatively large NPV increases relative to the change in wind generation. In the No New Wind Scenario, all but the Southeast region has lower electric sector investment value through 2050, with the North Central region experiencing a $73 billion reduction. The *Study Scenario*, however, achieves at least $35 billion greater electric sector investment value than *Business-as-Usual* in all regions but the Southeast. The North Central region, which includes the Dakotas and a large fraction of the Midwest, achieves $91 billion in increased investment value over 2017–2030, and that net increase persists over the whole study period (2017–2050).

4. Conclusions

We have examined how high wind penetration in the U.S. electric sector can affect the U.S. economy using a linked model that pairs the detailed electric sector representation of ReEDS with the general equilibrium economic perspective of USREP. This analysis can provide insights relevant to a wide range of stakeholders interested in interactions between renewable energy deployment, fossil fuel markets, electricity markets, and economic welfare with the broader goal of improving the understanding of renewable energy economic impacts.

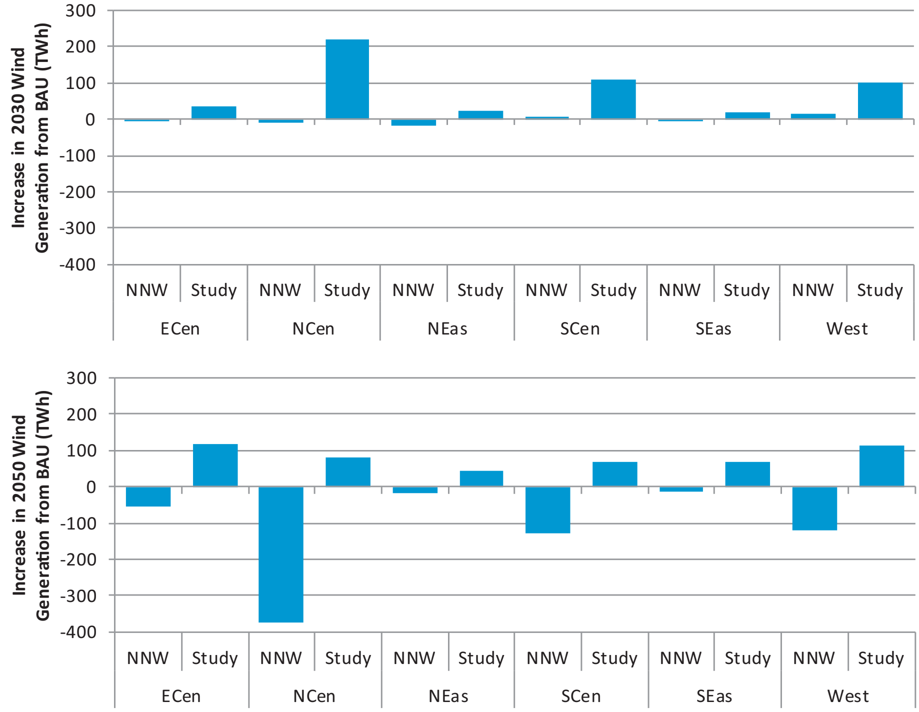

Fig. 16. The change in 2030 and 2050 wind generation relative to the *Business-as-Usual Scenario* for each region.

Within the electric sector, deploying cost-competitive wind (as in our *Business-as-Usual Scenario*) reduces electricity prices and promotes electricity demand growth relative to a *No New Wind Scenario* where wind capacity remains stagnant at 2016 levels. High levels of wind capacity deployment consistent with the *Wind Vision Study Scenario* (>380 GW in 2050) leads to a modest increase in electricity prices relative to the *Business-as-Usual* case, but the change is no greater than in the case of *No New Wind*.

Additional wind electricity displaces fossil fuels for electricity generation, and these reductions in fossil fuel demand depress fossil fuel prices. Natural gas prices appear more sensitive to changes in demand from the electric sector than coal prices, as coal exports can help

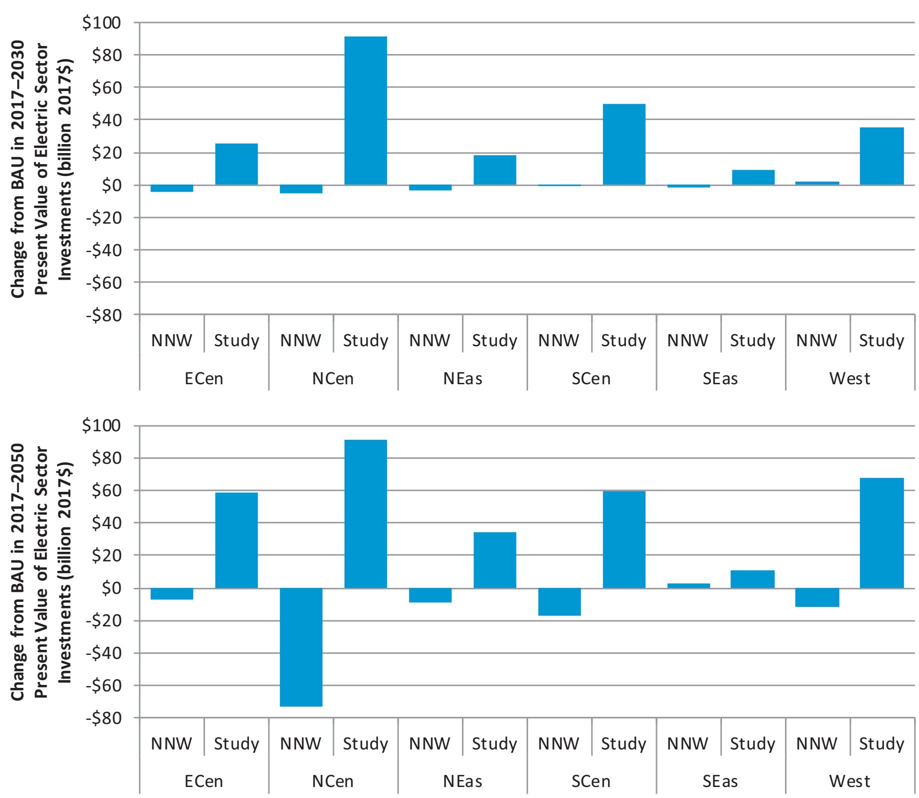

Fig. 17. Changes relative to *Business-as-Usual* of electric sector investment by region largely follow similar trends as regional wind generation.

mitigate the impact of reduced electric sector use. Increased wind generation beyond *No New Wind* reduces CO_2 emissions in the electricity sector and overall. Wind growth in the high-deployment *Study Scenario* reduces 2050 electric sector CO_2 by >20% and 2050 economy-wide CO_2 by 6% relative to *No New Wind*, with reductions of 11% and 3% relative to *Business-as-Usual*. Some CO_2 leakage to other sectors occurs when deploying less competitive resources, but observed leakage is <10%.

The emissions reductions with higher wind deployment are achieved alongside higher U.S. GDP and economic welfare relative to the *No New Wind Scenario* where wind capacity stagnates. Though the high-deployment *Study Scenario* has slightly lower GDP and welfare than *Business-as-Usual* in 2050, the present value for 2017–2050 is 0.02% higher for GDP and 0.04% higher for welfare due to annual improvements through the early 2040s that exceed 0.05% in the 2030s. These relative changes are small in the context of the total economy but still equate to tens of billions of dollars annually and have a cumulative net present value of \$150 billion GDP and \$192 billion in welfare. Welfare improvements are driven primarily by higher capital returns generated by increased electric sector investment along with lower electricity prices (when cost-competitive wind is deployed) and lower fossil fuel prices. Overall our results suggest that investment in wind capacity does not hinder economic growth and in fact could provide benefits to the U.S. economy, even in the case of high deployment. We acknowledge, however, that while wind primarily displaces PV in terms of capacity and a combination of PV, gas, and coal in terms of generation, our analysis does not systematically compare the economy-wide benefits of wind deployment to alternative scenarios presuming the increased deployment of any other specific generation technology.

These welfare gains are however not distributed equally across income classes. Investment effects dominate purchasing power effects, so high-income households benefit the most from wind deployment because they own a larger share of capital despite any progressive purchasing power effect of lower electricity and fossil fuel prices. Despite this generally regressive behavior, economic gains occur for all income classes in *Business-as-Usual* (relative to *No New Wind*). In the high-deployment *Study Scenario*, all but the lowest-income households benefit through 2030. After that, gains relative to *Business-as-Usual* tapper off, and many income classes become worse off. Lowest-income households do not profit from capital investments, and price effects harm them disproportionally in this scenario. These negative impacts, however, could potentially be mitigated by lower electricity prices if wind technology cost reductions were attained. Local wind deployment spurs regional investment, but a more detailed assessment of local electricity markets would be necessary to better assess regional differences in economic performance.

In summary, wind deployment can reduce fossil fuel dependence and CO_2 emissions while having minimal or even positive impacts on the U.S. economy.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2018.10.023.

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