International Journal of Energy Economics and Policy

ISSN: 2146-4553

available at http: www.econjournals.com

International Journal of Energy Economics and Policy, 2023, 13(2), 391-403.

Effect of Natural Gas Prices on Renewable Portfolio Standard Impacts

Christopher Hannum*

University of Central Asia, Tajikistan. *Email: christopher.hannum@ucentralasia.org

Received: 22 October 2022 **Accepted:** 20 February 2023 **DOI:** https://doi.org/10.32479/ijeep.13741

ABSTRACT

Climate policy in the United States is often carried out at the state level rather than the national level, including renewable portfolio standards for the electricity generation sector. We assess the impacts of the RPS in the State of Colorado, one of the first to be implemented, using a recursive dynamic CGE model CO-E. The RPS reduces real household income in the state by an annualized value of $134.8 million in 2025 if natural gas prices are low, but results in increased incomes with medium or high natural gas prices although with medium natural gas prices the RPS causes electricity prices to rise. The impacts of the RPS are negatively correlated with those of natural gas price shocks to the overall state economy. As a result, the RPS serves as a partial insurance policy for the State against natural gas price shocks, which adds $4.53 million to the annualized benefit of the policy.

Keywords: Electricity, Natural Gas, Energy Policy, Renewable Portfolio Standard, Computable General Equilibrium
JEL Classifications: C68, D58, Q48, R50

1. INTRODUCTION

Colorado, like many US States, follows an independent state-level energy and climate policy as a result of persistent gridlock in Washington. The state has approximately 5.8 million residents, a per capita income of $40,000 (US Census Bureau, n.d.) and consumes approximately 5 GWh of electricity per year of which 35% is produced from renewable sources (Energy Information Administration, n.d). Amendment 37, a ballot initiative, established the Colorado Renewable Portfolio Standard (henceforth RPS), which was later strengthened by Colorado House Bills 1281 and 1001. The Colorado RPS consists of three critical components: separate renewable energy requirements for cooperatives, municipal electric utilities, and investor-owned electric utilities as well as a distributed generation requirement (largely rooftop solar power) purchases by investor-owned electric utilities. Eligible renewable energy sources include solar thermal, photovoltaic, landfill gas, wind, biomass, hydroelectric, geothermal electric, recycled energy, anaerobic digestion and fuel cells using renewable fuels (US Department of Energy, n.d.). However, for Colorado by far the most cost-competitive generation technologies in this bundle have been wind power and more recently solar photovoltaic.

The share of renewable energy used by investor-owned electric utilities began at 15%, rising to 20% in 2015 and 30% in 2020 (US Department of Energy, n.d.). The RPS is less strict for small-town municipally owned electric utilities, with an initial 3% renewable requirement, rising to 6% in 2015 and 10% in 2020. A 2013 update, SB-1352, mandated 20% and 10% renewables by 2020 for larger and smaller cooperatives respectively. Investor-owned utilities were initially required to generate or purchase 1.25% of electricity for retail sale using Distributed Generation (DG), rising to 1.75% in 2015, 2% in 2017 and 3% in 2020 half from "retail" rather than "wholesale" DG. "Wholesale" DG refers to small-scale power plants of any type located close to consumers, "retail" DG to customer-owned, on-site generating capital as in renewable systems with net metering.

1.1. Trends in US Electricity Generation

The State of Colorado is far from unique in its adoption of state-level policies to promote clean energy in the electricity sector.

Currently 29 of the 50 states have adopted a renewable portfolio standard in electricity generation of one form or another (US Department of Energy, n.d.) with Alabama, Alaska, Arkansas, Florida, Georgia, Idaho, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Nebraska, North Dakota, Oklahoma, South Carolina, South Dakota, Tennessee, Utah, Virginia, West Virginia and Wyoming as the remaining holdouts. Maguire (2012) found no statistical support for influence of political party on RPS adoption, however more recently Thombs and Jorgenson (2020) determined that the impact of political party is limited to fossil-fuel producing states. However, US states without a renewable portfolio standard seem to have little in common aside from the level of support for the Republican Party in both local and national elections. Donald Trump received a median vote share in non-RPS states of 58.5% in 2020 as compared to 42.5% in RPS states. (MIT Election Data & Science Lab, 2017). Fossil fuel producing states are represented in both the RPS and non-RPS groups, for example four of the top ten US states by 2021 coal output have renewable portfolio standards (NMA, 2021). Colorado is both a fossil fuel producer and also a so-called "purple" state in which state-wide elections are tightly contested between the two parties. Therefore, the presence or lack of an RPS is assumed to represent an exogenous policy shock rather than an endogenous decision based on local resource abundance.

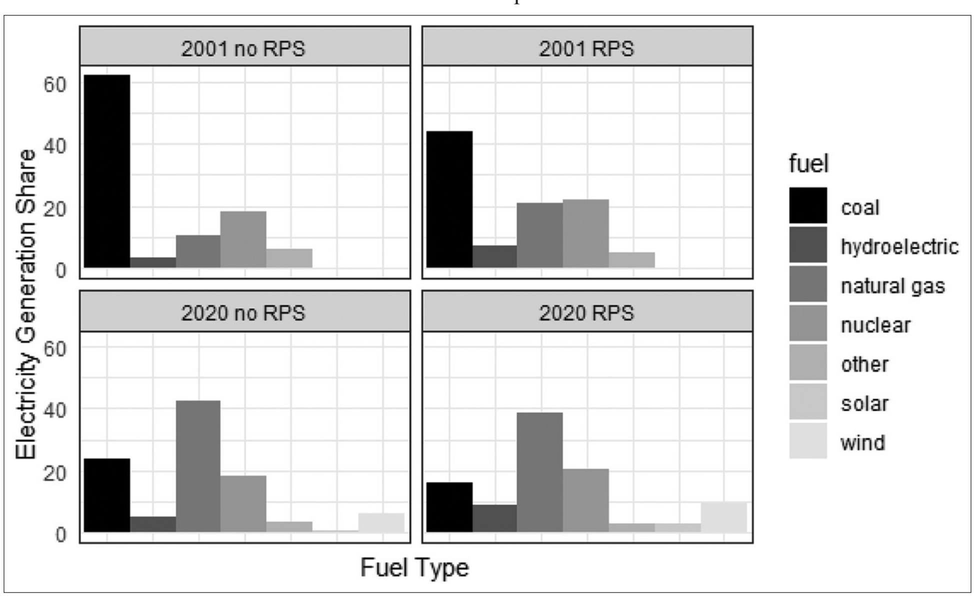
It is important for the purposes of this study to establish what the likely path for the Colorado electricity generation mix would have been in the absence of the exogenous policy shock presented by the 2004 RPS, perhaps driven by local preferences for environmental benefits and co-benefits of renewable energy (Holt and Wiser, 2007) as well as cost. We assume that in the absence of an RPS, Colorado's path would have been similar to the group of non-RPS states, including neighboring Wyoming from which Colorado purchases abundant cheap coal (Energy Information Administration, n.d.).

As shown in Figure 1 above, in 2001 RPS states were somewhat less dependent on coal and more dependent on natural gas, hydroelectric and nuclear power. Hydroelectric aside, the renewable share of generation was quite small in RPS and non-RPS states alike in 2001. In some respects, RPS and non-RPS states trends over the past 20 years are similar. Both groups have seen rapid transitions from coal to natural gas as improved technology in combined-cycle natural gas plants as well as increased capital costs for new coal-fired plants have led to a transition from coa l plants to baseload natural gas plants. Though this transition has taken place on both groups of states, it is somewhat more pronounced in non-RPS states. The decline in coal-fired generation for both groups has been approximately 2% per year as older coal plants are allowed to depreciate (Energy Information Administration, 2022). Fell and Kaffine (2018) find empirically that low gas prices and increased wind power capacity have together caused the across-the-board decline in US coal output, with a somewhat greater responsiveness to natural gas prices.

The two noteworthy differences in electricity generation trends between the non-RPS group and the RPS group are the differences in the growth of wind power and utility-scale solar power. Though other renewable generation technologies, such as geothermal, biomass, etc… are supported and encouraged by the Colorado RPS as well as those of many other states (US Department of Energy, n.d.) they have not seen enough investment to capture a significant generation share. According to EIA levelized cost estimates (LCOEs), wind power has long been the most cost competitive among renewables with lifetime project costs little higher than those for base load natural gas plants, thanks in part to federal tax benefits.

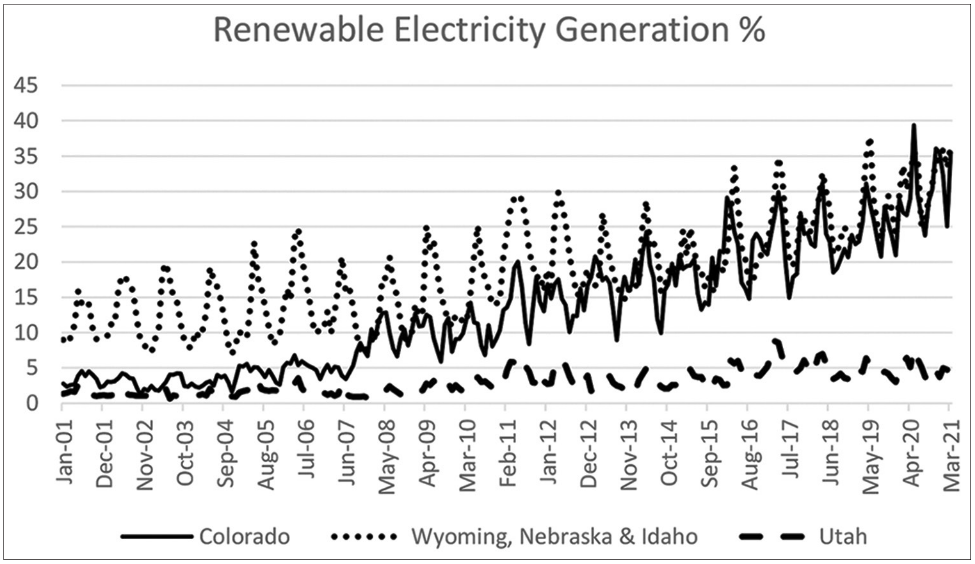
Figure 2 compares trends in monthly generation from renewable sources in Colorado to a set of comparable states in the region. Utah has an explicit renewable energy goal, but no policy instrument in place to ensure that it is met. Wyoming, Idaho and Nebraska have no renewable energy mandates with generation trends driven largely by cost. We can see that in Utah, as in

Figure 1: Electricity generation share trends by generation technology, a comparison of US states with RPS requirements to those without RPS requirements



Source: EIA

Figure 2: Comparative trends in renewable electricity generation between Colorado (RPS), Utah (renewable goals) and Wyoming, Idaho, and Nebraska (No Policy)



Source: EIA

Colorado, the renewable energy share was low in the early 2000s whereas in Wyoming, Idaho and Nebraska it was fairly high (due to hydropower facilities). In Utah, the renewable energy share remained low whereas in Colorado it has risen dramatically over two decades to match the Wyoming, Idaho, and Nebraska group.

All states show a similar transition away from coal power, driven more by cost than concern over CO_2 emissions. However, in the RPS states a significant portion of the new base load generation capacity takes the form of wind farms as opposed to combined-cycle natural gas plants. Wind power appears to be displacing new gas generation capacity as well as old coal generation capacity. We also see a non-trivial increase in utility-scale solar power generation in RPS states that we do not see in non-RPS states. One driver for investment in renewable generation has been state-level policy, but other drivers such as national subsidies on renewable generation capital and improvements in renewable technologies and these drivers affect both groups of states.

However, since wind, solar and other variable or intermittent generation technologies increase the system requirements for "peaker" plant use (Joskow, 2011), increased wind generation capacity may require the installation of more natural gas "peaker" capacity.

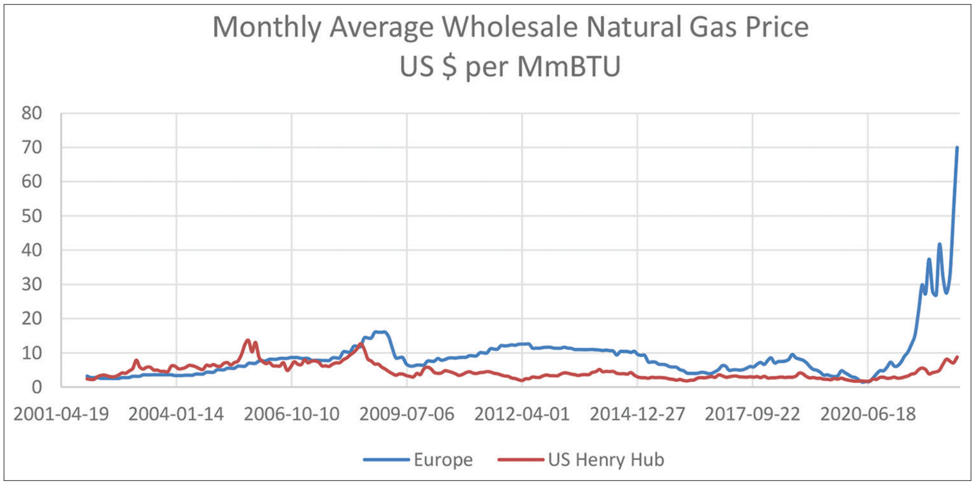
1.2. Natural Gas Price Uncertainty

The burning of natural gas to produce electricity produces only 0.5675 tons of CO_2 per mWh, compared to 1.1245 tons of CO_2 per mWh for electricity produced by burning coal (US Environmental Protection Agency, n.d.). As a result, natural gas has been seen as an important bridge to a low-carbon future powered by renewable energy sources and to be among the lowest cost methods by which to achieve modest short-term reductions in carbon emissions. In recent years technological innovations in the natural gas industry have greatly reduced the cost of reductions in carbon and other emissions through transition from coal-powered to gas-powered electricity generation in the United States (Jacoby et al., 2011). However, the reduced cost of gas-generated electricity may have the secondary effect of increasing the economic burden and reducing the desirability of such policies as renewable portfolio standards which mandate that a certain percentage of total energy or total electricity must come from sources classified as "renewable". While the transition away from coal and petroleum for electricity production in US states without an RPS has led primarily to a transition towards natural gas generation, in states with an RPS this transition moves towards both wind and natural gas. This suggests that a renewable portfolio standard is likely to decrease reliance on natural gas (Moniz et al., 2011).

However, a great deal of uncertainty exists surrounding the future of production of natural gas from nonconventional sources, which has played a dominant role in the recent American natural gas boom. As shown in Figure 3 even smoothed spot prices for natural gas are unstable. Natural gas spot prices, as calculated at the Henry Hub in Louisiana - the closest approximation to a national price - have ranged from near \$2 per mBTU in the late 1990s to more than \$6 or \$7 during the 2003-2007 housing boom and down again to the neighborhood of \$3 per mBTU in 2012 and 2013, then below \$2 again during the pandemic in 2020 only to rise to \$8.81 in August 2022 (International Monetary Fund, n.d.).

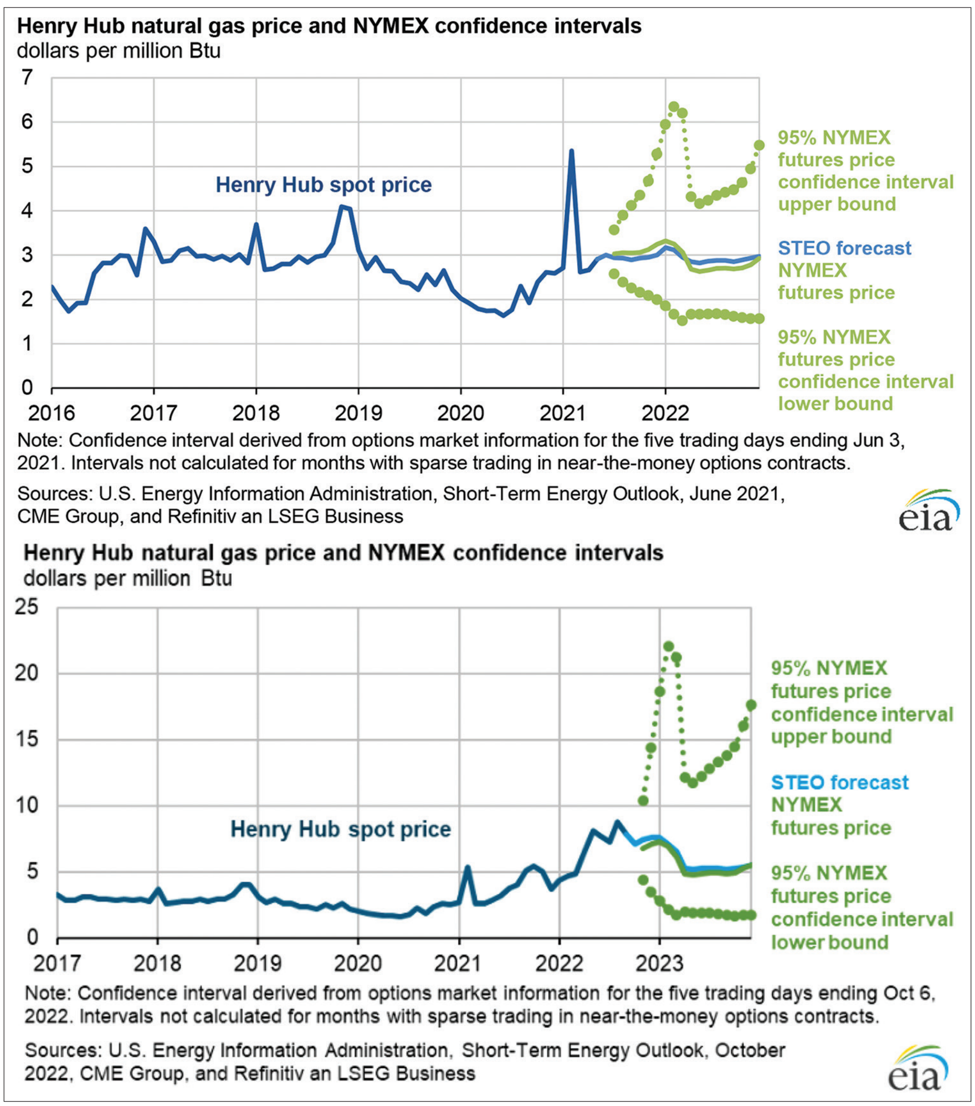
Forecasting long and short-run variation in natural gas prices is difficult. Prior to 2008, few would have foreseen the dramatic increase in US natural gas supply associated with innovations in hydraulic fracturing and the extraction of shale gas. Looking toward the future from 2004 when the Colorado RPS was enacted, stakeholders would have likely been concerned about rising costs of imports of liquefied natural gas that would soon be required by the US electricity sector. More recent speculation has centered on whether demand for natural gas and LNG export capacity will expand quickly enough to meet new supply (Wang and Krupnick, 2015; Krupnick et al., 2013; Joskow, 2013). As illustrated below

Figure 3: Monthly average wholesale natural gas prices



Source: International Monetary Fund

Figure 4: STEO natural gas price forecasts and confidence intervals



in Figure 4, short run natural gas price forecasts (based on futures contracts) as of June 2021 included a wide confidence band, with prices expected to range between $1.5 and $6.5 per mBTU over the next 18 months. Though wide, these forecast bands do not incorporate the possibility of extraordinary events and thus the $7.70 price of June 2022 fell well outside the confidence interval.

The confidence interval for forecasts made in October 2022 ranges as high as $22 per mmBTU and as low as $2 for January 2023.

As difficult as it would have been to correctly forecast the scale of the fracking boom and the associated impacts on US natural gas supply and natural gas prices, it will be similarly difficult to correctly forecast the future trajectory of shale gas in the United States and globally. Stocks of technically recoverable nonconventional natural gas reserves, costs involved in extraction from shale plays, rates of decline in production from existing wells and costs associated with future environmental regulation or increased enforcement of existing legislation regarding hydraulic fracturing all exhibit significant uncertainty which will impact future expected natural gas productivity and market prices (Joskow, 2013). While short run natural gas price forecasts tend to be based upon futures markets, long run natural gas price forecasts tend to be based on assessments of extraction costs (Moniz et al., 2011), given assumptions of perfectly competitive markets which would lead excessively costly projects to be abandoned.

Given (at least in the US) competition and free entry, in the long run natural gas prices ought to be just high enough to cover all project costs, leading to expectations that US natural gas prices will regress toward a long run $6 per mmBTU level, though they have not been consistently above this level since 2008. LCOEs for natural gas generation projects planned to come online by 2020, which will have a lifespan spanning several decades, incorporated such an assumption. Over such a time horizon it is potentially equally valid to consider two alternative scenarios, a doubling or a halving of long run natural gas prices relative to the baseline scenario included in those levelized cost estimates. In the former, we might assume that US natural gas prices converge towards the global average spot price due to strict controls placed on hydraulic fracturing in the US to protect groundwater supplies (Logan et al., 2013) making the US a potential market for LNG imports again. In the latter, we might assume either further innovation in hydraulic fracturing technology or a long-run maintenance of today's natural gas market status quo, which could be considered to be unsustainable, in which natural gas drilling remains economically viable despite low natural gas prices due to high prices for natural gas liquids (Energy Information Administration, 2013) or other incentives. Neither scenario is likely to result in a significant divergence from the current electricity generation technology path of transition (Logan et al., 2013) as the cost of natural gas generation would remain below that of advanced coal generation, but the costs associated with local energy policies such as HB-1365 and the Colorado RPS could be dramatically different.

1.3. Estimates of Energy Policy Impacts

This study will attempt to quantify the economic impacts of Colorado energy legislation, given a variety of possible paths for natural gas industry productivity and hence natural gas prices. How natural gas prices affect the medium and long-run economic costs of these policies will be assessed using a dynamic CGE model of the Colorado economy designed in conjunction with the National Renewable Energy Laboratory (National Renewable Energy Laboratory, n.d.) under a variety of assumptions regarding future productivity in the natural gas industry in Colorado and the United States as a whole. A baseline impact of each policy component will be estimated independently compared to a counterfactual simulation of the Colorado economy given no policy-induced restrictions or changes to the electricity sector after 2010 under the mean forecast for domestic natural gas wellhead prices from the EIA.

A number of studies have performed analyses along the same lines in order to consider the economic impacts of renewable portfolio standards and other state and local energy policies. Though RPS policies in the United States are typically a form of state or local government legislation, Palmer and Burtraw (2005) and Kydes (2007) analyze the national impacts using partial equilibrium energy models. A renewable portfolio standard is found to raise electricity prices and primarily displaces natural gas generation hence the impact of the RPS on electricity prices is sensitive to assumptions about natural gas prices (Palmer and Burtraw, 2005). Young and Bistline (2018) likewise find that policies to reduce carbon emissions that focus on gas do so at lesser cost than an RPS and result in a greater reduction in coal power. It is possible that such studies find such a strong substitution between renewables and gas for marginal generation because they ignore the role played by gas (but not coal) generation as a "peaker" complement to intermittent renewables. However, in a recent empirical analysis Feldman and Levinson (2023) find that renewable portfolio standards have led to decreased gas use and carbon emissions, but that their overall role in increasing renewable generation is less than commonly advertised. Stricter RPS standards, requiring greater than 15% or 20% renewables overall are estimated to incur higher costs as intermittency/variability costs rise (Carley et al. 2018). However, using the EIAs National Energy Modeling System, Kydes (2007) estimates that a nationwide RPS of 20% would raise US electricity prices by only 3% by 2020 relative to a baseline scenario.

Chen et al. (2009) review a number of studies that attempt to assess the economic and other costs of actual or proposed renewable portfolio standards at the state level, 28 studies in 20 states. Few studies surveyed are peer-reviewed, most produced by consultancies sometimes as part of the policy review process by one interested party or another. Though the degree of academic and mathematical rigor associated with the results is unknown, most point to a relatively modest impact of renewable portfolio standards. In contrast to the EIA NEMS estimate of a 3% increase in electricity price, the vast majority of studies reviewed by Chen et al. (2009) predict an increase in electricity prices of 1% or less. These are predictive that studies are do not involve complete CGE models. Empirical studies also exist. Greenstone and Nath (2020) using a difference-in-differences approach to analyze States' recent experiences, find an increase in electricity prices of 11% over 7 years after enacting RPS legislation

Though use of fully-fledged CGE models to analyze renewable portfolio standards and other state-level energy policies is somewhat rare neither is it novel. Böhringer et al. (2012) use a CGE model designed for the Canadian province of Ontario to analyze the economic impacts of a feed-in tariff for local solar distributed generation. In analyzing the concept of "green jobs", Böhringer et al. (2012) find that while the feed-in tariff creates jobs in green sectors it decreases employment overall, they argue that energy policies intended to benefit the environment should be promoted based on environmental benefits rather than as job creating programs. In analyzing renewable energy and energy efficiency scenarios, CGE results from the state-level Berkeley Energy and Resource (BEAR) Model (Roland-Holst and Kahrl, 2009) find the opposite result. Renewable energy is found to be "job intensive" relative to fossil fuel generation and stronger pushes towards energy efficiency and renewable electricity generation are found to lead to greater job gains. Barbose et al. (2016) find that US renewable portfolio standards support approximately 200,000 so-called "green jobs" nationwide.

Some have sought to analyze state and local policy not simply because this is the form that much energy and climate policy in the United States, due to the inability to pass legislation or lack of interest at the federal level, but objectively in order to assess the desirability of state and local policy relative to national policy where the latter a practical possibility (Goulder and Stavins, 2010). In assessing the impact of state and local climate policy, in which the potential global benefits of CO2 emissions reductions are not affected by physical relocation of emissions producing activities, "leakage" of such activities across state (or national) lines is of importance in determining the amount of actual CO2 reduction and associated global benefit associated with the policy (Bushnell et al., 2008). This study will not attempt to quantify CO2 reductions of Colorado energy policies and will instead focus on local economic benefits and costs of the policies. An alternative line of analysis for state level policies is the optimal design of a system of state and federal policies (Bushnell et al., 2008) and of state level policies within an existing federal framework. In the case of Colorado, the desirability of certain environmental policies, particularly the RPS, is directly dependent upon the existing incentive framework created by the production tax credit, a framework which is not considered as a policy variable.

In addition, the complex relationship between natural gas and renewable generation is of particular importance. Barbose et al. (2016) finds evidence for a substantial spillover benefit of an RPS in reducing natural gas demand and thereby natural gas prices, reducing consumers' gas bills accordingly. In modeling these relationships, Colorado should be considered as a fuel-producing State with 5.5 million cubic feet of natural gas produced per day in 2019 (Energy Information Administration, n.d.). Allcott and Keniston (2018) find strong evidence that gas-producing US States have economically benefited from the shale gas boom during the past few decades, including a 1% increase in real wages for each one standard deviation increase in oil and gas endowment. This boom has been associated with high gas sector productivity and low gas prices and this study will particularly focus on the impacts of the Colorado RPS against this backdrop.

2. METHODOLOGY

2.1. Energy Sector Modeling

Inclusion of Colorado energy policy changes in a standard Arrow-Debreu CGE model requires several modifications. The model includes five generation types, coal, natural gas, wind, utility-scale solar and hydroelectric power (as Colorado has no nuclear power facilities) as well as a transmission sector which buys electricity from generators and sells it on the grid to end consumers. Application of the RPS requires a nesting in the transmission sector production function which allows substitution between electricity produced using coal and natural gas and among renewable sources (in this model only wind, solar and hydroelectric) but forbids substitution between the renewable and non-renewable nests. The proportion of transmission sector electricity input that must be purchased from renewables is determined exogenously by policy – given a higher cost for renewable than non-renewable (chiefly natural gas) electricity generation, no simulation would induce a higher percentage of renewable generation were the model specified in such a way as to allow this to occur.

Because Colorado's RPS treats investor-owned (largest-scale) utilities differently from municipal utilities and small-scale independent generators, these must be treated as separate sectors for the purposes of model specification. Since municipal utilities are typically located in areas that are not served by larger IOUs, representative households and production sectors demand electricity from IOU and municipal transmission sectors with no possibility of substitution between the two electricity inputs. Small-scale "wholesale distributed generation", which represents plants of any generation type with a nameplate capacity of 30 MW or lower modeled after the actual assortment of such generators in the state of Colorado today. The output of wholesale DG plants is assumed to be sold only to the IOU transmission sector, at higher cost, in the proportions mandated by RPS legislation.

For the purposes of model specification, "retail distributed generation" is considered to represent only residential and commercial use of photovoltaic solar arrays with net metering. This necessitates the creation of two new sectors, Commercial PV and Residential PV. Commercial PV produces electricity, which it sells to both industry sectors and the IOU transmission sector. Residential PV produces electricity, which it sells to both households and the IOU transmission sector. This electricity is treated as a separate production input or consumption good than the electricity purchased from either the IOU or municipal transmission sectors, with a higher willingness-to-pay explained by corporate social responsibility (CSR) and environmental concerns.

In the Colorado Energy (CO-E) CGE model, wholesale electricity produced by generation (IE sectors defined largely by production technology GENcoal (coal), GENgas (base load natural gas), GENpeak (natural gas "peaker"), GENwind (wind), GENhydro (hydroelectric), UTILpv (utility-scale photovoltaic for wholesale distributed generation), RESpv and COMMpv (residential and commercial photovoltaic, respectively, for retail distributed generation). Other generation types such as geothermal or biomass are absent from the model because they represent an insignificant share of total generation in the state of Colorado and do not receive special treatment under the RPS legislation as solar photovoltaic does.

IE sectors demand a fuel-type-specific capital type (for coal, natural gas, wind, hydroelectric and solar photovoltaic) which is not demanded outside the IE sectors. This specification differs from a sector-specific capital type formulation primarily in that an existing natural gas plant could be used by either GENpeak or GENgas, as base load or "peaker" generation depending on relative demand and that existing solar arrays are assumed to be transferrable between the three solar sectors. Baseline estimates for these capital stocks are provided by the National Renewable Energy Laboratory and the Energy Information Administration as of 2011 and scaled back based on changes in state generation capacity estimates (Energy Information Administration, 2007) for the baseline simulations' starting point of 2006, the year before the first RPS requirements in the state.

For each IE sector a productivity parameter $PROD_{ie,t}$ determines a non-unitary baseline price, $P0_{ie}$, based on recent median EIA levelized cost of energy (LCOE) estimates. Levelized cost estimates represent an estimation of the average cost of generation over the lifetime of the plant, which typically lasts several decades, where the planning and construction process begins today but the plant is assumed to come online in approximately 5 years (Table 1).

$$YE_{ie,t} = PROD_{ie,t} L_{l,ie,t}^{\alpha_{l,ie}} LA_{ie,t}^{\alpha_{la,ie}} K_{k,ie,t}^{\alpha_{k,ie}} Y_{i,ie,t}^{\alpha_{i,ie}} FX_{ie,t}^{\alpha_{fx,ie}} \tag{1}$$

$$\sum_l \alpha_{l,ie} + \sum_k \alpha_{k,ie} + \sum_i \alpha_{i,ie} + \alpha_{la,ie} + \alpha_{fx,ie} = 1 \; for\; all\; ie \in IE \tag{2}$$

Where $YE_{ie,t}$ represents real output for generation sector ie at time t, $PROD_{ie,t}$ is the productivity parameter for generation sector ie at time t, $L_{l,ie,t}$ are the quantities of labor input from labor type l for generation sector ie at time t. $LA_{ie,t}$ represents the quantity of land used by generation sector ie at time t, $K_{k,ie,t}$ represents the quantity of capital input type k used by generation section ie at time t, $Y_{i,ie,t}$ is the quantity of good i produced by domestic sector i used as an intermediate in production by generation sector ie at time t and $FX_{ie,t}$ represents the quantity of imported inputs used by generation sector ie at time t.

As shown in equations (1) and (2) above, electricity generation by IE sectors is specified using a simple Cobb-Douglass production function with constant returns to scale in all inputs. Among IE sectors, GENpeak and solar sectors have the highest LCOEs and hence the smallest values for $PROD_{ie,t}$, GENgas and GENwind the lowest LCOEs and hence the largest values for $PROD_{ie,t}$. All $PROD_{ie,t}$ values are scaled such that the average cost of wholesale electricity in the base year remains unity. Of the seven 8 IE sectors, only the outputs of COMMpv and RESpv are demanded directly by firms and households respectively. This represents demand for commercial and residential solar array output by owners, rather than indirectly through the grid. While COMMpv and RESpv output is demanded both by end consumers and grid sectors, output of other IE sectors is demanded exclusively by grid sectors as an intermediate input as shown in equation (3) below.

The three grid (GR) Sectors are IOU (investor-owned utilities), COOP (electric cooperatives) and MUNI (municipal utilities). COOP and MUNI assumed to service primarily non-urban consumers, their output is therefore demanded disproportionately by those industries and household groups most often found outside of metropolitan areas, with breakdowns based on estimates from the American Community Survey Public Use Microdata (ACS PUMS). Based on estimates from the Colorado Rural Electric Association, COOP is assumed to be 10% less productive than IOU while MUNI is assumed to be approximately 17% more productive than IOU due to differences in electric meters (customers) per kilometer of grid. This effect is represented by the productivity parameter $PROD_{gr,t}$, leading to non-unity baseline prices for each generation type but an average baseline electricity price of approximately unity for the system as a whole.

$$Y_{gr,t} = PROD_{gr,t} L_{gr,t}^{\alpha_{l,gr}} LA_{gr,t}^{\alpha_{la,gr}} K_{gr,t}^{\alpha_{k,gr}} A_{i,gr,t}^{\alpha_{i,gr}} ELEC_{gr,t}^{\alpha_{elec,gr}} \tag{3}$$

Production of the grid sector output $Y_{gr,t}$, retail electricity, is specified using a simple Cobb-Douglas functional form with constant returns to scale. In addition to labor (L), land (LA), capital (K) and intermediate inputs (A) each grid sector demands a sector specific wholesale electricity bundle $ELEC_{gr,t}$.

$$ELEC_{gr,t} = min\left(\frac{RENEW_{gr,t}}{\gamma_{gr,t}^{RENEW}}, \frac{NONRENEW_{gr,t}}{\gamma_{gr,t}^{NONRENEW}} \right) \tag{4}$$

$$NONRENEW_{gr,t} = YE_{GENgas,t}^{\beta_{GENgas,gr,t}} YE_{GENcoal,t}^{\beta_{GENcoal,gr,t}} YE_{GENpeak,t}^{\beta_{GENpeak,gr,t}} \tag{5}$$

$$RENEW_{gr,t} = min\left(\frac{YE_{GENhydro,gr,t}}{\gamma_{gr,t}^{GENhydro}}, \frac{SOLAR_{gr,t}}{\gamma_{gr,t}^{SOLAR}}, \frac{WIND_{gr,t}}{\gamma_{gr,t}^{WIND}} \right) \tag{6}$$

$$WIND_{gr,t} = min\left(\frac{YE_{GENwind,gr,t}}{0.9542}, \frac{YE_{GENpeak,gr,t}}{0.048} \right) \tag{7}$$

$$SOLAR_{gr,t} = min\left(\frac{YE_{UTILpv,gr,t}}{\gamma_{gr,t}^{UTILpv}}, \frac{DG_{gr,t}}{\gamma_{gr,t}^{DG}} \right) \tag{8}$$

$$DG_{gr,t} = YE_{RESpv,gr,t}^{\alpha_{RESpv,gr,t}} YE_{COMMpv,gr,t}^{\left(1-\alpha_{RESpv,gr,t}\right)} \tag{9}$$

As shown in equation (4) above, $ELEC_{gr,t}$ is produced using a Leontief formulation from a renewable energy bundle RENEWgr,t and a non-renewable energy bundle NONRENEWgr,t with the required shares determined by technology or policy parameters $\gamma_{gr,t}^{RENEW}$ and $\gamma_{gr,t}^{NONRENEW}$.

Table 1: Sets and elements in the computable general equilibrium model

Set	Description	Subscript	Element list
IE	Electricity generation sectors	ie	GENcoal, GENgas, GENwind, GENhydro, GENpeak, RESpv, COMMpv,
L	Labor types	l	L1, L2, L3, L4, L5
K	Capital types	k	KAP, Kcoal, Kgas, Kwind, Kpv, Khydro, Kfs
I	Industry sectors	i	Agric, Mining, Coal, NatGas, Utilities, Const, Manuf, WHTR, Retail, TransWare, Info, FinIns, RealEst, HGSER, Manage, Educ, unijc, Admin, HealthCare, Arts, LodgeRest, OtherServ, PubAdm
GR	Grid sectors	gr	IOU, COOP, MUNI

As shown in equation (5) above, the nonrenewable energy bundle for each sector is created using a simple Cobb-Douglas production function to transform GENgas, GENcoal and GENpeak into NONRENEW assuming an elasticity of substitution of unity. Baseline generation shares in the NONRENEW bundle are calibrated based on pre-RPS 2006 proportions for the Colorado electricity sector (Energy Information Administration, 2007). As opposed to changes in the generation type mix due to renewables standards, proportions of different fossil fuel types are not mandated by a regulatory authority and thus substitution in response to changes in relative prices can take place.

As shown in equation (6) below, the renewable energy bundle for each sector is policy determined and hence follows a Leontief production technology with no substitution between $YE_{GENhydro,gr,t}$ and the solar and wind bundles. The bundle $WIND_{gr,t,}$ a component of the renewable energy bundle, includes a fixed proportion of both $YE_{GENwind}$ and $YE_{GENpeak}$, as shown in equation (7). Due to the intermittent or variable nature of wind, which can neither be feasibly ramped up or down due to current demand conditions and which cannot be relied upon to operate at capacity when demand is predictably high (as base load GENcoal can) an increase in the share of wind generation is assumed to necessitate additional usage of and capacity for low-efficiency GENpeak. The amount of $YE_{GENpeak}$ bundled with a unit of $YE_{GENwind}$ is derived from estimates by Xcel energy of the total system costs associated with the variable nature of wind power (Wiser and Bolinger, 2012).

Equations (8) and (9) show the creation of the solar energy bundle $SOLAR_{gr,t}$ using Leontief production technology (with no opportunity for substitution due to policy) from YE_{UTILpv} and the distributed generation bundle $DG_{gr,t}$, which is in turn created (see equation 2.8) from YE_{RESpv} and YE_{COMMpv}. Proportions are determined by the parameters $\gamma_{gr,t}^{UTILpv}$, $\gamma_{gr,t}^{DGpv}$, $\gamma_{gr,t}^{COMMpv}$ and $\gamma_{gr,t}^{RESpv}$. In the baseline scenario these are defined in order to calibrate the model to pre-RPS 2006 generation type shares, in RPS simulations these γ parameters are policy determined.

Whereas additional dependence on wind energy by the grid is expected to lead to an increased need for "peaker" plants due to the inherently intermittent and variable nature of the resource and the generation technology, additional dependence on solar energy is not expected to lead to the same result. Solar energy, by coincidence rather than by design, generates the most electricity at times of the day and times of the year when electricity demand is at its highest, when businesses are operating and when air conditioners are running (Heidel, Kassakian & Shmalensee, 2012; Boyle, 2009). Wind has no such natural tendency to blow hardest when the days are hot or during the workday.

A deliberate modeling decision was taken to apply a single cost and productivity estimate for each technology in all years of the dynamic simulation, rather than basing them on annual current LCOE estimates (as most of this transition path is historical) or on a forecasted LCOE series based on expectations of technological change and fuel price as of 2006. This is due both to the extreme uncertainty regarding expectations for future LCOEs and the inability of the recursive dynamic CGE model to fully account for these expectations and their uncertainty in calculating a forward-looking investment path. The single set of LCOEs used as the basic for calculation of productivities in generation comes from the Annual Energy Report from the Energy Information Administration in 2013 (Energy Information Administration, 2013). It is only in 2015 that the requirements for renewable generation in Colorado begin to bite, in that they require substantially greater renewable generation proportions than existed prior to 2006. It is assumed that investment in new generation technology in order to meet the 2015 mandate will be able to take advantage of 2013 technologies and productivity. However, the model does not incorporate any productivity increases past 2013 for wind, gas or solar. Current LCOEs are quite similar for combined-cycle natural gas plants and onshore wind plants, as they were in 2013. There has, however, been a dramatic improvement in the relative competitiveness of utility-scale solar photovoltaic since 2013 Cost has fallen by more than 80% and in the US solar is now cost competitive with wind and gas. However the most dramatic improvements have been over the past couple of years, too late to meet the mandates of the Colorado RPS which reached full force in 2020.

2.2. Policy Simulations

In general, the rigidity associated with electricity bundling in the CGE model is based upon requirements of the RPS itself. Estimates of the impact of the RPS on the electricity sector and the Colorado economy are solely derived from modification of the required proportions rather than the rigidity associated with these requirements, which is a given even in non-RPS simulations. As such, simulation results are best taken as representative of the impact of scaling up the RPS from its original, relatively modest level rather than from the system rigidity that the RPS brought upon the system. In fact, baseline values for γ parameters in the absence of an RPS requirement led to greater usage of renewables overall than the initial, low requirement in 2007 that the RPS mandated as the actual renewable share of generation capacity in 2006 was more than adequate.

The energy policy changes included in HB 10-1365 consist of three critical changes which must be modeled independently (Rudolph, 2014). The first is the early retirement of 551 MW of coal-fired generating capacity, equal to approximately 10% of existing stock. This is modeled as a simple reduction in the endowment of "coal generation capital" for the Colorado economy. The second and third changes are more complex. The bill mandates the retrofitting of 742 MW, approximately 13.6% of existing stock, with enhanced emissions controls. This is modeled as representing the change from conventional to advanced coal-fired generation as defined by the EIA, which increases capital requirements per mWh by approximately 28.5%. The production function for coal-fired generation is modified by the policy to require approximately 4% more capital per unit of output. Finally, the bill requires two power station units, with a combined capacity of 463 MW, currently fueled by coal but capable of burning natural gas to "fuel-switch" to natural gas in 2014 and 2017 respectively. Natural gas is the more expensive fuel by far as measured by energy content; however coal-fired stations require significantly larger capital investments per MW of nameplate capacity. This hybrid generating sector must be modeled independently; a sector which requires the non-fuel inputs of coal-fired generation but the fuel inputs of gas-fired generation. This sector will produce no output in the model prior to year 2014.

Current policy requires a 30% RPS for IOUs, a 20% RPS for larger co-ops, a 10% RPS for municipal utilities and smaller co-ops. It also requires that 1.5% of electricity sold by IOUs, 0.5% sold by co-ops and 0.375% sold by municipal utilities be purchased from wholesale DG with equal proportions from retail DG. Simulations will estimate the economic impact of mandated increased in RPS requirements in 2015, 2017 and 2020 as compared to a counterfactual policy scenario under which no RPS was passed. Initial requirements when the RPS was passed were non-binding, as the mandated proportions of renewables were already in use. The economic impact of each component (the RPS requirement for IOUs, the RPS requirement for municipal utilities, the wholesale DG carve-out, the retail DG carve-out, coal capacity requirement, coal plant retrofitting and fuel-switching) will be assessed separately and in combination under a variety of scenarios involving natural gas sector productivity and hence the natural gas price, ranging from a 50% decrease in productivity relative to mean EIA expectations to a 100% increase in productivity relative mean EIA expectations.

In order to simulate Colorado's RPS:

- Set $\gamma_{gr,t}^{RENEW}$ and $\gamma_{gr,t}^{NONRENEW}$ to match RPS mandate
- $\gamma_{gr,t}^{RENEW} >$ mandated % due to inclusion of $YE_{GENpeak}$ in the bundle
- Set $\gamma_{gr,t}^{SOLAR}$ to match "solar carve-out", the required proportions of UTILpv, COMMpv and RESpv are already calibrated in the baseline scenario
- Set $\gamma_{gr,t}^{GENhydro}$ and $\gamma_{gr,t}^{GENwind}$ to force investment in wind (least-cost renewable) over hydroelectric
- Simulation begins in 2006, the last year before RPS mandate
- Assumed to move steadily towards the next binding mandate (initial mandates too low to constrain utilities) – as shown in Figure 4 above.

In order to simulate HB10-1365, the Clean Air – Clean Jobs Act

- Shock to endowment of Kcoal in 2012 (10% decrease)
- Additional K input requirement in production of $YE_{GENcoal,t}$ beginning in 2012 equivalent to 4.76% of Kcoal input use per unit, raising cost per unit by approximately 3%
- GENhybrid sector created, which requires fuel inputs in same proportions as GENgas per unit of output, other inputs as per GENcoal and is typically inactive in the model as it is a higher cost method of producing GENgas sectoral output
- ~8% of Kcoal converted to Kfs (fuel switching), the technology-specific capital type used by GENhybrid to turn on GENhybrid.

3. RESULTS

Due to assumptions regarding levelized costs (with gas only 2/3 the cost of coal) and the transition path for electricity generation technology shares in the absence of a renewable portfolio standard, in the counterfactual baseline scenario – a steady transition towards natural gas and away from coal for base load generation – we see a slow and steady decrease in the cost of electricity and hence the price of electricity given competitive market assumptions. In the absence of policy shocks, between 2006 and 2025 the real price of electricity would have been expected to decline by approximately 8% as older and less efficient coal plants were replaced by newer and more efficient combined cycle natural gas plants. In the two alternative baseline simulations, with increased and decreased natural gas productivity respectively, the transition towards natural gas and away from coal is expected to continue unabated. Even with natural gas prices twice as high as currently forecast levels, combined cycle natural gas generation remains less costly than new coal-burning plants and as a result electricity prices decline over time with high, low and medium gas price assumptions.

However, large shocks to natural gas productivity can be expected to have a relatively sizeable impact on the Colorado economy by 2025 as shown in Table 2 below. The impact on employment is relatively modest, particularly for an increase in natural gas sector productivity which creates fewer than 100 jobs overall, but the change in state and local tax revenues (nearly $1 billion in current $) and real household consumption (a loss of $5.658 billion with low natural gas productivity, a gain of $1.891 billion with high natural gas productivity) – a proxy for welfare - are substantial. The impact on government revenues represents an increase or decrease of approximately 2.7% of expected revenues in 2025 in the baseline scenario. The impact on real household consumption represents a drop of approximately 2.5% relative to expected consumption in 2025 in the baseline scenario when natural gas productivity is low and an increase of approximately 0.8% when natural gas productivity is high.

The impact of changing natural gas productivity is felt through several different channels, the most important of which are the reduction in electricity and heating costs which benefit consumers and certain industries and also through a net export effect. Demand for Colorado "exports" to the ambiguously defined rest-of-world is assumed to have a unitary elasticity of demand and no explicit requirement for exports to equal imports. Demand for "imports" within Colorado, on the other hand, follows an Armington specification wherein Colorado firms and households demand a composite good composed of both domestic and "foreign" varieties of the same good. As a result, when productivity increases lower the price of both Colorado and imported natural gas their respective shares in the composite good do not change. In situations such as this, where Colorado demand for the Armington natural gas good exhibits inelastic demand overall the effect of the productivity shock can be a significant increase in net exports of natural gas from Colorado. This increase in net exports lifts the prices of domestic homes, capital and land, raises prices for certain (less traded) sectoral outputs and leads to an increase in real wages barely balancing an increased cost of living. Migration in the CO-E model responds exclusively to changes in real wages, rather than to changes in capital or other income. Most of any long-run increase in total employment is due to changes in migration; hence the impact of the net export effect on total employment is muted despite large gains in consumption and income.

With natural gas productivity and prices based upon long run assumptions in recent EIA LCOEs, which is to say no additional shocks to natural gas sector productivity, relative to a baseline without policy shocks HB 10-1365 leads to higher electricity prices and decreased overall employment. This is accompanied by falling state and local tax revenues and falling real household consumption as it represents a rapid and inefficient transition to gas.

A key modeling assumption is that grid sectors have at least a slight preference for the status quo in terms of generation technology mix and that different generation types such as base load coal and base load gas are not perfect substitutes. Were this not the case, GENcoal and GENgas output would sell for the same price as GENgas, with any policy impacts felt first and foremost in dramatic swings in the market price of the fuel-type-specific capital Kcoal or Kgas. This would be plausibly compatible with assumptions of perfect competition built into CGE models, provided a genuinely infinite or near infinite elasticity of substitution between coal and gas generation. However, past research (Dagher, 2011) has found elasticities of substitution to be significantly lower, particularly in the short run. However, electricity sectors are generally not perfectly comptetive, but rather heavily regulated in an effort to imitate a perfectly competitive outcome (Colorado Department of Regulatory Agencies, n.d.) . As a result, as GENcoal output is made more costly to produce through legislation, and as the relatively inefficient GENhybrid fuel-switching sector is activated these cost increases are passed on to consumers in HB-1365 simulations through higher electricity prices.

Adding the renewable portfolio standard to the policy mix leads to a loss of 13,000 jobs relative to the baseline model with "medium" gas prices (no productivity) shock and HB 10-1365 in 2025 (by which time each policy's full effects should be felt). This is accompanied by rising state and local tax revenues and rising real household consumption, though not for the highest income household groups. The apparently paradoxical result of decreasing employment with increasing consumption has a simple explanation. Wind and solar electricity generation is vastly more capital intensive than traditional fossil fuel generation and as a result, the RPS mandate increases the capital share of income and decreases the labor share of income in addition to raising the price of electricity relative to the baseline transition path. Migration and labor supply are both driven by changes in real wages rather than changes in capital or other income there (Table 3).

The Colorado RPS increases tax revenues and consumption, although it raises electricity prices above the baseline transition path. Though the difference in cost between wind power and base load natural gas generation is substantial if federal tax benefits are ignored the difference is small when these are included. In addition, as this is a regional rather than a national model the assumption is that the burden of subsidy payments falls primarily on taxpayers outside of the state. Hence, an increase in wind and solar generation leads to an increase in net transfers from the federal government to the state economy.

Of primary interest is how the economic impacts of the RPS, which decreases Colorado dependence on natural gas, differ in the low, medium and high gas price scenarios. The impact of the RPS on total employment is negative in all three scenarios, though job losses are 9000 greater in the low gas price scenario than in the high gas price scenario. The effect on employment is nearly symmetrical when natural gas sector productivity is low with an increase in job losses of slightly more than 4,000. Using real household consumption as a proxy for total welfare, the sign of the impact of the Colorado RPS on the price of natural gas. The RPS increase in real household consumption is $179 million greater in

Table 2: Impact of natural gas prices

Baseline w/o HB 10-1365	Low gas price	Mid gas price	High gas price
Employment (# jobs)	96.96	0	−64793.76
State total Tax Revenue (mil $)	597.21	0	−597.58
Local Total Tax Revenue (mil $)	355.18	0	−409.25
Real Household Consumption (mil $)	1891.1	0	−5658.6
Baseline with HB 10-1365			
Employment (# jobs)	−2663.3	−6013.14	−71508.16
State total Tax Revenue (mil $)	583.36	−11.26	−608.7
Local Total Tax Revenue (mil $)	341.51	−10.96	−420.42
Real Household Consumption (mil $)	1707.3	−329.6	−6029.3

Table 3: Impact of energy policies (all values in 2025)

RPS added to baseline with HB 10-1365	Low gas price	Mid gas price	High gas price
Employment (# jobs)	−18278.66	−13031.82	−9297.6
State total Tax Revenue (mil $)	83.83	75.34	70.67
Local Total Tax Revenue (mil $)	31.77	29.89	32.04
Change in Real Household Consumption (mil $)			
HH1 ≤ $10,000	67.48	74.62	76.73
$10,000<HH2≤$20,000	57.82	60.66	60.58
$20,000<HH3≤$40,000	19.42	35.53	44.82
$40,000<HH4≤$50,000	2.13	21.66	33.68
$50,000<HH5≤$70,000	−1.93	26.55	50.36
$70,000<HH6≤$100,000	−106.8	−42.72	5.62
$100,000<HH7	−172.91	−43.71	39.84
Total	−134.8	132.6	311.7

the high gas price scenario than in the medium gas price scenario. In the low gas price scenario, which assumes improvements in fracking technology or other reasons to continue shale gas projects for which gas revenues do not cover costs, the impact of the RPS on real household consumption becomes negative overall, though four of the seven household groups see increases in consumption. Total real household consumption falls $134.4 million below the estimated baseline transition path value in 2025.

4. CONCLUSION

At first glance it might appear appropriate, given total real household consumption as the most appropriate proxy for economic welfare, to view the Colorado RPS as risky policies. Though the Colorado RPS will also have associated environmental and health benefits given certain assumptions about future natural gas prices (and federal tax credits) the RPS could be beneficial even in the absence of environmental benefits. It would be tempting to see the RPS as a gamble – one that would result in losses should the price of natural gas stay low but result in gains otherwise. Such a policy might be preferred to the status quo, the transition-to-gas path followed by non-RPS states, given a relatively low probability of lower natural gas prices and/or a relatively risk-neutral state government.

The addition of potentially substantial environmental benefits would alter the equation substantially. Previous studies such as Hannum et al. (2017) have estimated the damages associated with NOx and SO2 associated with fossil fuel electricity in Colorado to be approximately $540 and $1,052 per ton respectively using the APEEP model (Muller and Mendelsohn, 2007). However, as emissions of SO2 in particular are dramatically lower from natural gas plants than from coal plants the additional ancillary benefits (Bell et al. 2008; Burtraw et al. 2003) associated with the Colorado RPS are fairly modest, estimated to be between $4 and $6 million per year above and beyond the approximately $35 million per year associated with the transition-to-gas path (Hannum et al. 2017). The Colorado RPS would also result in substantial reductions in CO2 emissions of potentially between 4 and 5 million tons (Hannum et al. 2017). With an estimated appropriate value of carbon dioxide emissions reductions of between $13 and $31 depending upon the choice of appropriate discount rate (Greenstone et al., 2013) CO2 reductions associated with the Colorado RPS represent a substantial ancillary benefit, potentially enough to balance out the negative impact on total real household consumption with low gas prices. In addition, these estimates of potential ancillary benefits ignore the other environmental impacts of natural gas production in the state and outside of the state, including possible groundwater contamination and potentially large methane emissions from the wellhead or in transmission of natural gas from the wellhead, estimated to be between 3.6% and 7.9% of all natural gas extracted (Howarth, Santoro & Ingraffea, 2011). However, while most ancillary benefits associated with NO2 and SO2 emissions are relatively localized those associated with CO2 and methane emissions reductions are global and only a minute fraction of the total $13 to $31 impact could be expected to be felt within a state. For the purposes of state or local energy policy, it may not be rational to use global ancillary benefits as justification for policy, unless the "warm glow" effect is expected to be equivalent to the actual global damages averted. It is well and good that the Colorado RPS appears potentially desirable when local impacts are considered exclusively as other benefits, though potentially large, may not give an appropriate benchmark for regional policy.

If we assume that the three natural gas scenarios given above are equally likely, the Colorado RPS can be analyzed using an expected utility framework with constant relative risk aversion using an estimated θ for the United States of 1.39 (Gandelman and Hernández-Murillo, 2014).

$$U(c) = \frac{1}{1-\theta} c^{1-\theta} \tag{10}$$

$$E(V) = p_1 U_1(c_1) + p_2 U_2(c_2) + p_3 U_3(c_3) \tag{11}$$

As real household income is higher with the RPS even with medium natural gas prices, the average real household income is $103.17 million higher with the RPS across the scenarios. It is tempting to view the set of outcomes of the RPS (−134.8, +132.6, +311.7) as a risky gamble. However, the Colorado economy is already heavily exposed to the uncertainties and economic risks associated with natural gas prices themselves. Potential gains and losses to the Colorado economy in terms of total real household consumption from natural gas productivity shocks themselves, as for any region which is both a substantial producer and consumer of natural gas, dwarf the expected impacts of the RPS and push the economy in opposite directions. The certainty equivalent of the set of baseline scenarios is a real household income 1.595 billion lower, suggesting an amount the State would be willing to sacrifice to avoid any natural gas price risk. As income effects of the RPS in the presence of natural gas shocks are negatively correlated with the effects of the shocks themselves, the Colorado RPS acts as an insurance policy against economic risks associated with natural gas productivity shocks and with a coefficient of relative risk aversion of 1.39 this effect adds $4.53 million to the net benefit of the policy. What is more, in contrast to other potential means of hedging or insuring against such risks in state energy policy, such as long-term contracts for "imported" natural gas or derivatives contracts (Bolinger, 2009), the expected value of the RPS is estimated to be positive rather than negative – and an insurance policy with a negative price is a deal too good to pass up.

REFERENCES

Allcott, H., Keniston, D. (2018), Dutch disease or agglomeration? The local economic effects of natural resource booms in modern America. The Review of Economic Studies, 85(2), 695-731.

Barbose, G., Wiser, R., Heeter, J., Mai, T., Bird, L., Bolinger, M., Carpenter, A., Heath, G., Keyser, D., Macknick, J., Mills, A., Millstein, D. (2016), A retrospective analysis of benefits and impacts of US renewable portfolio standards. Energy Policy, 96, 645-660.

Bell, M., Davis, D., Cifuentes, L., Krupnick, A., Morgenstern, R., Thurston, G. (2008), Ancillary human health benefits of improved air quality resulting from climate Change Mitigation. Environmental Health, 7(1), 1-18.

Böhringer, C., Rivers, N., Rutherford, T., Wigle, R. (2012), Green jobs and renewable electricity policies: Employment impacts of Ontario's feed-in tariff. The BE Journal of Economic Analysis and Policy, 12(1), 1-10.

Bolinger, M. (2009), The Value of Renewable Energy as a Hedge Against Fuel Price Risk: Analytic Contributions from Economic and Finance Theory. Lawrence Berkely National Laboratory Working Paper. Available from: https://escholarship.org/uc/item/65g8f2t4

Boyle, G. (Ed.). (2009), Renewable electricity and the grid: the challenge of variability. Routledge. New York, NY.

Burtraw, D., Krupnick, A., Palmer, K., Paul, A., Toman, M., Bloyd, C. (2003), Ancillary benefits of reduced air pollution in the US from moderate greenhouse gas mitigation policies in the electricity sector. Journal of Environmental Economics and Management, 45(3), 650-673.

Bushnell, J., Peterman, C., Wolfram, C. (2008), Local solutions to global problems: Climate change policies and regulatory jurisdiction. Review of Environmental Economics and Policy, 2(2), 175-193.

Carley, S., Davies, L.L., Spence, D.B., Zirogiannis, N. (2018), Empirical evaluation of the stringency and design of renewable portfolio standards. Nature Energy, 3(9), 754-763.

Chen, C., Wiser, C., Mills, A., Bolinger, M. (2009), Weighing the costs and benefits of state renewable portfolio standards in the United States: A comparative analysis of state-level policy impact projections. Renewable and Sustainable Energy Reviews, 13(3), 552-566.

Colorado Department of Regulatory Agencies (DORA). Available from: https://dora.colorado.gov/consumer-protection-utilities [Last accessed on 2023 Mar 9].

Dagher, L. (2011), Natural gas demand at the utility level: An application of dynamic elasticities. Energy Economics, 34(4), 961-969.

Energy Information Administration. (2007), Short Term Energy Outlook. Available from: https://www.eia.gov/outlooks/steo/archives/jan07.pdf [Last accessed on 2022 Sep 24].

Energy Information Administration. (2013), Annual Energy Outlook 2013. Available from: https://www.eia.gov/outlooks/archive/aeo13 [Last accessed on 2022 Sep 24].

Energy Information Administration. (2022), Annual Energy Outlook 2022. Available from: https://www.eia.gov/outlooks/aeo [Last accessed on 2022 Sep 24].

Energy Information Administration. Colorado State Profile and Energy Estimates. Available from: https://www.eia.gov/state/?sid=CO [Last accessed on 2022 Oct 16].

Environmental Protection Agency. About the US Electricity System and Its Impact on the Environment. Available from: https://www.epa.gov/energy/about-us-electricity-system-and-its-impact-environment [Last accessed on 2022 Sep 24].

Feldman, R., Levinson, A. (2023), Renewable Portfolio Standards. The Energy Journal, 44(5), 1-21.

Fell, H., Kaffine, D.T. (2018), The fall of coal: Joint impacts of fuel prices and renewables on generation and emissions. American Economic Journal: Economic Policy, 10(2), 90-116.

Gandelman, N., Hernández-Murillo, R. (2014), Risk Aversion at the Country Level. Federal Reserve Bank of St. Louis Working Paper 2014-005B.

Goulder, L., Stavins, R. (2010), Interactions between State and Federal Climate Change Policies. NBER Working Paper.

Greenstone, M., Kopits, E., Wolverton, A. (2013), Developing a social cost of carbon for US regulatory analysis: A methodology and interpretation. Review of Environmental Economics and Policy, 7(1), 23-46.

Greenstone, M., Nath, I. (2020), Do Renewable Portfolio Standards Deliver Cost-Effective Carbon Abatement? University of Chicago: Becker Friedman Institute for Economics Working Paper. p. 2019-2062.

Hannum, C., Cutler, H., Iverson, T., and Keyser, D. (2017), Estimating the implied cost of carbon in future scenarios using a CGE model: The Case of Colorado. Energy Policy, 102, 500-511.

Heidel, T. D., Kassakian, J. G., and Schmalensee, R. (2012), Forward pass: Policy challenges and technical opportunities on the US electric grid. IEEE Power and Energy Magazine, 10(3), 30-37.

Holt, E., Wiser, R. (2007), The treatment of renewable energy certificates, emissions allowances, and green power programs in state renewables portfolio standards. United States: Lawrence Berkeley National Laboratory. Available from: https://escholarship.org/uc/item/4jj146vk.

Howarth, R. W., Santoro, R., and Ingraffea, A. (2011), Methane and the greenhouse-gas footprint of natural gas from shale formations: A letter. Climatic change, 106, 679-690.

International Monetary Fund, Global Price of Natural Gas, EU [PNGASEUUSDM]. St. Louis: Federal Reserve Bank. Available from: https://fred.stlouisfed.org/series/PNGASEUUSDM [Last accessed on 2022 Oct 15].

International Monetary Fund, Global Price of Natural Gas, US Henry Hub Gas [PNGASUSUSDM]. St. Louis: Federal Reserve Bank. Available from: https://fred.stlouisfed.org/series/PNGASUSUSDM [Last accessed on 2022 Oct 15].

Jacoby, H., O'Sullivan, F., Paltsev, S. (2011), The influence of shale gas on US energy and environmental policy. Economics of Energy and Environmental Policy, 1(1), 37-52.

Joskow, P. (2011), Comparing the costs of intermittent and dispatchable electricity generating technologies. American Economic Review: Papers and Proceedings, 100(3), 238-241.

Joskow, P. (2013), Natural gas: From shortages to abundance in the United States. The American Economic Review, 103(3), 338-343.

Krupnick, A., Wang, Z., Wang, Y. (2013), Sector Effects of the Shale Gas Revolution in the United States. Resources for the Future. Discussion Papers. p. 13-21.

Kydes, A. (2007), Impacts of a renewable portfolio generation standard on US energy markets. Energy Policy, 35(2), 809-814.

Logan, J., Lopez, A., Mai, T., Davidson, C., Bazilian, M., Arent, D. (2013), Natural gas scenarios in the US power sector. Energy Economics, 40, 183-195.

Maguire, K. (2012), Prices or politics? The influence of markets and political party changes on oil and gas development in the United States. Energy economics, 34(6), 2013-2020.

MIT Election Data and Science Lab. (2017), U.S. President 1976-2020 (V6) [Data Set], Harvard Dataverse. https://doi.org/10.7910/DVN/42MVDX

Moniz, J., Jacoby, H., Meggs, A. (2011), The Future of Natural Gas: An Interdisciplinary MIT Study. United States: MIT Energy Initiative. Available from: https://energy.mit.edu/research/future-natural-gas

Muller, N., Mendelsohn, R. (2007), Measuring the damages of air pollution in the United States. Journal of Environmental Economics and Management, 54(1), 1-14.

National Mining Association. (2021), U.S. Coal Production by State and Rank. Available from: https://nma.org/wp-content/uploads/2021/10/coal_prod_by_state_and_rank_21.pdf [Last accessed on 2022 Sep 24].

National Renewable Energy Laboratory. 80 and 100 Meter Wind Resource Potential for the United States. Available from: https://www.nrel.gov/docs/fy10osti/48036.pdf [Last accessed on 2022 Sep 24].

Palmer, K., Burtraw, D. (2005), Cost-effectiveness of renewable electricity policies. Energy Economics, 27(6), 873-894.

Roland-Holst, D., Kahrl, F. (2009), Energy Pathways for the California Economy. Berkeley ARE, Research Paper No. 0903241. Available from: https://are.berkeley.edu/~dwrh/CERES_Web/Docs/energy%20pathways%20final%20report.pdf

Rudolph, M. (2014), HB10-1365, Clean Air/Clean Jobs Act. National

Governors Association, Governors' Energy Advisors Policy Institute. Available from: http://www.nga.org/files/live/sites/NGA/files/pdf/1206PolicyInstituteRudolph.pdf [Last accessed on 2014 Mar 12].
Thombs, R.P., Jorgenson, A.K. (2020), The political economy of renewable portfolio standards in the United States. Energy Research and Social Science, 62, 101379.
US Census Bureau. QuickFacts Colorado. Available from: https://www.census.gov/quickfacts/CO [Last accessed on 2022 Oct 16].
US Department of Energy. Database of State Incentives for Renewables and Efficiency. Available from: https://www.dsireusa.org [Last accessed on 2022 Sep 24].
US Environmental Protection Agency (n.d.). About the US electricity system and its impact on the environment. Availablr from: https://www.epa.gov/energy/about-us-electricity-system-and-its-impact-environment [Last accessed on 2022 Sep 24].
Wang, Z., Krupnick, A. (2015), A retrospective review of shale gas development in the United States: What led to the boom? Economics of Energy and Environmental Policy, 4(1), 5-18.
Wiser, R., Bolinger, M. (2013), 2012-Wind Technologies Market Report. US Department of Energy. Available from: https://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf
Young, D., Bistline, J. (2018), The costs and value of renewable portfolio standards in meeting decarbonization goals. Energy Economics, 73, 337-351.