SIERRA CLUB

November 23, 2015

VIA ELECTRONIC MAIL

Nicole Singh, Executive Director
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RE: Comments of the Sierra Club Regarding RGGI 2016 Reference Case Analysis Assumptions

Dear Ms. Singh and Members of the RGGI Board:

Please accept these initial comments submitted on behalf of the Sierra Club, its nearly 100,000 members in the Regional Greenhouse Gas Initiative (RGGI) region, and its more than 600,000 members nationwide. The Sierra Club is deeply appreciative of the leadership that the RGGI states have shown over the past decade to combat the threat of climate disruption through the RGGI program. EPA's final Clean Power Plan—many elements of which track the structure developed by the RGGI states—is a powerful testament to this leadership. Building on RGGI's successful structure, the Sierra Club strongly endorses the extension and continued improvement of the RGGI program through this 2016 program review, and urges the RGGI states to ensure that the program not only complies with the Clean Power Plan but also keeps states on a course to meet their own 2030 and 2050 state climate targets.

The Sierra Club looks forward to providing additional comments by the December 4th deadline specifically addressing the Key Topics identified by the RGGI board. Based on our understanding that adjustments to the IPM modeling reference case may necessitate input prior to that date, we are offering these initial comments now regarding the modeling inputs and assumptions for the RGGI 2016 reference case.

I. Incorporate State 2030 Climate Goals into the Modeled Reference Case

All of the RGGI states have endorsed or established economy-wide climate targets for 2030. These targets, together with the relevant sources of authority, are set forth in Attachment A to these comments. As discussed below, these 2030 goals are directly connected to states' longer-term 2050 climate targets, and are informed by the current climate science, reflecting an understanding that the states must take timely and aggressive action to avoid the worst impacts of climate disruption. To ensure that the reference case accurately reflects the universe of relevant existing state policies, the Sierra Club urges RGGI to incorporate these 2030 state climate targets into the modeled reference case.

Incorporation of state economy-wide climate targets into IPM necessitates allocation of a share of the emission reductions to the electric sector. In the long-term, it will be critical to obtain meaningful emission reductions from all sectors—electric, transportation, buildings, industry, and agriculture. For practical and regulatory reasons, in the near term, the bulk of the emission reductions will continue to come from the electric sector.[1] Vehicle fleet turnover to enable significant penetration of zero emission vehicles, for example, while critically important will nevertheless take time. The Sierra Club has retained Synapse to develop a rigorous analysis of the anticipated allocation of emission reductions to the electric sector assuming a least cost buildout toward compliance with 2030 climate goals. The results of this analysis will be shared with RGGI once they are available, and are anticipated to be available in the next month.

To the extent that the IPM modeling is moving forward on a more compressed timeframe, a potential approach to allocation would be to attribute emission reductions to the electric sector based on the electric sector's share of the emission reductions to date, or based on prior analyses that have modeled buildouts toward economy-wide targets. For example, Clarke *et al.* (2014) summarized the results of nine top energy-environment-economy models looking at reducing economy-wide domestic greenhouse gas emissions by 50% and 80% by 2050.[2] The authors observed that these models call for reductions in the electric sector in excess of 75% to achieve a 50% reduction in economy-wide greenhouse gas emissions.[3] With the existence of low cost, zero emission power generation alternatives already on the market today, and regulatory structures available to ensure these come online, it is reasonable to expect that the electric sector over the next decade and a half will continue to produce the lion's share of the economy's carbon reductions, and this should be reflected in the IPM modeling assumptions.

II. Extend Modeling to 2050 and Incorporate States' 2050 Climate Goals to Ensure that Near-Term Investments Are Not Incompatible with RGGI States' Long-Term Climate Vision

Not only is it important to incorporate states' 2030 climate goals into the model to ensure near-term buildout will achieve those goals, but it is also important for the modeling to meaningfully incorporate states' 2050 climate goals. All but one of the RGGI states has adopted a 2050 climate goal (see Attachment A). These 2050 goals closely cluster around an 80% economy-wide reduction in greenhouse gas emissions from 1990 levels—the benchmark recommended by the Intergovernmental Panel on Climate Change. Extension of the modeling to 2050 and incorporation of states' longer-term climate goals is important because the book life of certain investments that will be made between now and 2030 will extend out beyond 2050. Consequently, it is important that states develop some understanding of whether those investments are compatible with states' goals for 2050. By way of example, a widespread investment in long-lived combined cycle natural gas plants and supporting infrastructure over the

[1] Leon E. Clarke et al., Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling, The Energy Journal, Vol. 1, at 21 (Special Issue 1: The EMF24 Study on U.S. Technology and Climate Policy Strategies) (2014) (noting that "electricity is the least-challenging sector to decarbonize directly so it takes on the largest initial emission reductions."), provided as Attachment B.
[2] *Id.* at 9.
[3] *Id.* at 21.

coming decade and a half may simply be incompatible with states achieving an 80% reduction by 2050 and necessitate replacement of these resources before the end of their book lives. The Sierra Club encourages RGGI to extend its modeling to 2050 and incorporate states' 2050 climate goals to ensure that the model results through 2031 are consistent with states' desired 2050 climate future. To be sure, Sierra Club understands that confidence around the accuracy of modeled outcomes decreases as timeframes extend further into the future. Yet there is no uncertainty about the existence of states' 2050 mandates for an 80% reduction in greenhouse emissions. If RGGI is to continue to fulfill its critical role of helping states' achieve their carbon objectives, the RGGI planning process should incorporate and be informed by these mandates.

III. Include Compliance with the Clean Power Plan in the Modeled "Reference Case"

At this point, the Clean Power Plan is a final rule and should be treated congruently with all other final rules, which RGGI has directed ICF to incorporate into the reference case. Although we recognize the RGGI states' interest in understanding what policy scenarios might look like with and without the Clean Power Plan, compliance with the Clean Power Plan is not the only or even the primary driver of greenhouse gas reductions in the RGGI region over the coming decades. First, incorporation of RGGI's 2020 region-wide cap—which ICF has indicated is already part of the reference case—already effectively incorporates compliance with the Clean Power Plan, as the RGGI 2020 cap is *lower* than the new plus existing source mass cap for the RGGI states under the Clean Power Plan for 2030. Second, as noted above, states in the RGGI region have all articulated 2030, and in all except one case 2050, climate targets that necessitate emission reductions from the electric sector beyond what the Clean Power Plan mandates. In light of these facts, it is misleading to structure the modeled reference case around exclusion of the Clean Power Plan. Exclusion of the Clean Power Plan from the reference case simply results in modeling the rest of the country as having no price or limit on carbon, which (thankfully) is no longer the case. Moreover, it mistakenly suggests that the Clean Power Plan, and not RGGI states' own climate goals, will be the primary driver of carbon reductions from the electric sector in the RGGI region over the coming years.

IV. Ensure Demand Forecasts Are Realistic and Do Not Overestimate Demand and Underestimate Penetration of Energy Efficiency and Demand Response

As discussed at the November 17th meeting, demand is the most important input to the IPM model. It dictates how much generation the model will need to procure. Consequently, forecasting demand as accurately as possible is critical. Regional transmission organizations have a long history of over-predicting demand and underestimating penetration of energy efficiency and demand response, which is unsurprising in light of the inherently conservative role they play in ensuring resource adequacy and system reliability. However, incorporation of such mis-predictions exaggerates modeled costs.

To mitigate this concern, the Sierra Club encourages RGGI to revise RTO estimates of energy efficiency penetration, as necessary: (a) to incorporate the most current short- and long-term state energy savings and peak demand reduction requirements and targets, and (b) where states lack numerical targets or are exceeding their existing targets, to build out a trajectory that projects current energy saving trends into the future. Notably, utilities in Massachusetts recently submitted their 2016-2018 joint statewide three-year plan, which provides for an annual savings goal of 2.93% of retail sales.[4] Comparable levels—certainly of at least 2.0% per year—should be used as a proxy for other states that, like Massachusetts, have a mandate to procure "all cost effective" energy efficiency, including Rhode Island, Maine, Connecticut, and Vermont.

V. Ensure That Assumptions Regarding Cost and Performance of New Generation Incorporate the Most Current Developments and Track Long-Term Trends

Given the dramatic improvements in the performance of renewable technologies and the declines in levelized cost, it would be easy to underestimate performance and overestimate cost of renewable technologies when attempting to look into the future fifteen years. Taller wind turbines with longer blades, for example, are already projected to enable capacity factors in excess of 60% for land-based wind in the near future: With 140 meter hub heights, the National Renewable Energy Laboratory (NREL) estimates nearly 2 million square kilometers in the contiguous United States that would support capacity factors of over 60%.[5] It is important not only that recent technological advances are incorporated into the model, but also that the model assumes some trajectory for future improvements in performance and reductions in levelized cost for wind and solar.

With regard to cost, Lazard's recently released November 2015 unsubsidized levelized cost of energy comparison identifies the levelized cost of onshore wind at $44-66/MWh in the Northeast.[6] Thin film utility scale solar is $50-60/MWh.[7] These unsubsidized ranges compare very favorably with the cost of natural gas combined cycle at $52-78/MWh.[8] Trends in unsubsidized levelized costs for both wind and solar are dramatic. Over the past six years, Lazard documents a 61% decrease in the levelized cost of wind[9] and an 82% decrease in the levelized cost of solar photovoltaics.[10] While these trends are not strictly linear, Lazard's analysis shows that the low end levelized cost for both wind and solar has uniformly declined year-on-year for the past six years, driven by "material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors."[11] As these trends are expected to continue into the future, it is important that the modeling not freeze cost and performance figures at 2015 levels for the next fifteen years, but instead project forward realistic trajectories of improving performance and declining cost consistent with the history of the industries and best analysis of future performance.

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[4] Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan, 2016-2018, D.P.U 15-160 to D.P.U. 15-169 (Oct. 30, 2015), at 12, available at http://ma-eeac.org/wordpress/wp-content/uploads/Exhibit-1-Gas-and-Electric-PAs-Plan-2016-2018-with-App-except-App-U.pdf. .
[5] NREL, United States (48 Contiguous States) – Potential Wind Capacity; Cumulative Area vs. Gross Capacity Factor, available at http://apps2.eere.energy.gov/wind/windexchange/pdfs/wind_maps/us_contiguous_wind_potential_chart.pdf.
[6] Lazard, Levelized Cost of Energy Analysis—Version 9.0 (Nov. 2015), at 9.
[7] *Id.*
[8] *Id.*
[9] *Id.* at 10 (average percent decrease of high end and low end of levelized cost range).
[10] *Id.* (average percent decrease of high end and low end of levelized cost range).
[11] *Id.*

For purposes of projecting forward cost and performance trends, the Sierra Club recommends that the RGGI states use NREL's 2015 Annual Technology Baseline (ATB) and accompanying report.[12] The ATB includes detailed cost and performance data (both current and projected) for both renewable and conventional technologies and is widely accepted for the type of modeling that the RGGI states are proposing.

VI. Model Sensitivities that Include and Exclude a Second Relicensing for Existing Nuclear Facilities

ICF is currently proposing to model all nuclear plants as retiring at 60 years of age after a single relicensing. By contrast, as noted by ICF, the Energy Information Administration assumes existing nuclear plants will receive a second relicensing and will operate for a lifespan of 80 years. As ICF indicated at the November 17th RGGI stakeholder meeting, under an assumption of a single relicensing approximately 40 GW of nuclear will retire between 2030 and 2040. Consequently, if the IPM modeling is extended out to 2050, the assumption that is made regarding number of relicensing opportunities for nuclear plants will potentially have dramatic implications for the need for new generation and overall modeled cost. The Sierra Club urges RGGI and ICF to model sensitivities that alternately include and exclude a second relicensing for existing nuclear facilities to fully understand the implication that this significant assumption has on the model results.

VII. Incorporate the Most Current Data and Developments into the Reference Case

We appreciate efforts by RGGI and ICF to incorporate the latest developments into its reference case assumptions. To this end, we flag several recent developments that we encourage ICF to incorporate into the model as feasible:

- New England states clean energy Request for Proposals (RFP): On November 12th, Massachusetts, Connecticut and Rhode Island jointly issued their final clean energy RFP, with an expectation of regulatory approval by the end of 2016. A timeline can be found here: http://cleanenergyrfp.com/timeline/. The reference case should incorporate projected results of this procurement.

- PJM load forecast: PJM will be releasing its 2016 forecast next month and has indicated in a draft modeling document released on November 16th that it plans to use its 2016 forecast for that modeling.[13] If the timing works out, ICF should use the PJM 2016 rather than the PJM 2015 forecast.

Thank you for your consideration.

Respectfully submitted,

[12] Available at http://www.nrel.gov/analysis/data_tech_baseline.html.
[13] PJM, Clean Power Plan Analysis PJM Draft Modeling Document (Nov. 16, 2015), available at http://www.pjm.com/~/media/committees-groups/committees/mc/20151116-webinar/20151116-item-02-pjm-clean-power-plan-analysis-draft-modeling-document.ashx.

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December 4, 2015

VIA ELECTRONIC MAIL

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RE: Supplemental Comments of the Sierra Club

Dear Ms. Singh and Members of the RGGI Board:

The Sierra Club respectfully submits the following comments as a supplement to the joint stakeholder comments being submitted concurrently today.

I. Environmental justice and meaningful participation

As identified in the joint stakeholder comments being filed concurrently today, the Sierra Club supports use of the RGGI framework as the compliance pathway for EPA's Clean Power Plan (CPP). The Sierra Club also strongly supports the requirements in the final CPP for ensuring the meaningful participation of affected communities, including low-income communities and communities of color. Fenceline communities bear a disproportionate share of the pollution burden from power generation. And low-income communities and communities of color frequently live in locations most vulnerable to the direct impacts of climate disruption, often with fewer options available to mitigate these impacts. The Sierra Club urges the RGGI states to expeditiously fulfill their participation obligations under the CPP and begin reaching out to these impacted communities and soliciting their feedback and participation early in the planning process. This is critical to ensure the full range of voices are heard from and to help ensure that the process yields results that benefit all affected stakeholders.

In addition, the CPP encourages states to conduct their own environmental justice analyses in developing their compliance strategies. The Sierra Club urges the RGGI states to heed this charge from EPA and to evaluate and analyze how implementation of RGGI at the cap levels recommended in the joint stakeholder comments would impact fenceline and low-income and environmental justice communities with a goal of identifying any potential inequalities that may be created so that they can be proactively addressed.

II. Achieving 100% clean energy

As set forth in the joint stakeholder comments, the Sierra Club views RGGI as the appropriate and necessary pathway to lock in electric sector emissions consistent with states' 2030 and 2050 economy-wide climate goals. As the climate science is rendering increasingly apparent, achieving even these goals alone is unlikely to stave off very serious impacts of climate disruption. Collectively, we need to continue to push for further and faster reductions, with the goal of decarbonizing the electric sector as rapidly as possible. To this end, the Sierra Club applauds the leadership of the RGGI states to date and urges that they continue to show leadership in moving toward a goal of 100% clean and carbon-free energy generation.

Thank you for your consideration.

Respectfully submitted,

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Regional Greenhouse Gas Initiative State 2030 and 2050 Economy-wide Climate Goals

State	2030 Target	2050 Target	Sources
Connecticut	35-45% below 1990	80% below 2001	2030: Conf. of New England Govs. Resolution 39-1 (http://www.cap-cpma.ca/data/Signed%2039-1En.pdf) 2050: C.G.S. 22a-200a (enacted by H.B. 5600) (https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm)
Delaware	30% below 2008	n/a	2030: Climate Framework for Delaware (Dec. 31, 2014) (http://www.dnrec.delaware.gov/energy/Documents/The%20Climate%20Framework%20for%20Delaware.pdf)
Maine	35-45% below 1990	75-80% below 2003[a]	2030: Conf. of New England Govs. Resolution 39-1 (http://www.cap-cpma.ca/data/Signed%2039-1En.pdf) 2050: Maine Rev. Stat. ch. 3-A § 576(3) (enacted by PC 2003, C. 237) (http://legislature.maine.gov/statutes/38/title38sec576.html)
Maryland	40% below 2006	Up to 90% below 2006	2030: Recommendation of the Maryland Commission on Climate Change (Oct. 29, 2015) 2050: Md. Env. Code § 2-1201 (2009) (http://law.justia.com/codes/maryland/2013/article-gen/section-2-1201/)
Massachusetts	35-45% below 1990	80% below 1990	2030: Conf. of New England Govs. Resolution 39-1 (http://www.cap-cpma.ca/data/Signed%2039-1En.pdf) 2050: Mass.Gen.L. ch. 21N § 3(b) (https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter21N/Section3)
New Hampshire	35-45% below 1990	80% below 1990	2030: Conf. of New England Govs. Resolution 39-1 (http://www.cap-cpma.ca/data/Signed%2039-1En.pdf) 2050: 2009 New Hampshire Climate Action Plan (http://des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan/documents/nhcap_final.pdf)
New York	40% below 1990[b]	80% below 1990	2030: 2015 New York State Energy Plan (http://energyplan.ny.gov/Plans/2015) 2050: Executive Order No. 24 (2009) (http://www.dec.ny.gov/energy/71394.html)
Rhode Island	35-45% below 1990	80% below 1990	2030: Conf. of New England Govs. Resolution 39-1 (http://www.cap-cpma.ca/data/Signed%2039-1En.pdf) 2050: Resilient Rhode Island Act of 2014, Sec. 42-6.2-2 (http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.HTM)
Vermont	35-45% below 1990	75% below 1990	2030: Conf. of New England Govs. Resolution 39-1 (http://www.cap-cpma.ca/data/Signed%2039-1En.pdf) 2050: 10 V.S.A. § 578 (enacted by S. 259) (http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT168.HTM)

[a] = "Long term" target; date not specified
[b] = "Energy Sector" only – excludes agriculture

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AUTHORS: Please see back pages for information on the proper style of submissions.

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THE EMF24 STUDY ON U.S. TECHNOLOGY AND CLIMATE POLICY STRATEGIES

A Special Issue of
The Energy Journal

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THE EMF24 STUDY ON U.S. TECHNOLOGY AND CLIMATE POLICY STRATEGIES

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Preface

Policy makers often rely on sweeping statements that, they insist, lead us inexorably in the "right" direction. However persuasive the rhetoric, the dissonance in their pronouncements makes it clear that the real truth, imprecise as it might be, must lie in the depths of the details.

The Energy Modeling Forum at Stanford has for years contributed to our foundational understanding of these critical details. Their projects analyze, model and test ideas in energy, environment and climate through thematic clusters of works. The present collection is the 24th such enterprise which gathers a series of wide-ranging interdisciplinary studies that focus on the relationship between U.S. technologies and climate change strategies.

Some of the results confirm previous findings, for example, that achievement of meaningful GHG reductions will entail a profound transformation of energy systems and there is a great deal of uncertainty about the best way to accomplish this transition. But the works drill down to examine a host of relationships and interactions. Among these are interactions between command-and-control and market based policies; interrelationships between electricity and transport policies; bioenergy, land use and trade in agricultural products; and, the relative cost of regulatory vs market based approaches to mitigation.

It is with great pleasure that The Energy Journal hosts this Special Issue devoted to deepening our understanding of these intricate relationships. It is our earnest hope that this research will contribute to supporting good policy discussions with scientifically supported substance.

Adonis Yatchew
Editor-in-Chief, *The Energy Journal*
May 15, 2014

EMF Sponsorship

Financial support from a wide range of affiliated and sponsoring organizations allows the Forum to conduct broad-based and non-partisan studies. Research grants from the U.S. Department of Energy and the U.S. Environmental Protection Agency have provided base support for the EMF for many years. During the period during which this study was completed, the Forum also gratefully acknowledges support for its studies from the following organizations:

America's Natural Gas Alliance
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Encana
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Exxon Mobil
Lawrence Livermore National Laboratory
MITRE Corporation
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Sandia National Laboratory
Southern Company
Statoil Hydro
Talisman Energy
TransCanada
Williams Energy

Introduction to EMF 24

Allen A. Fawcett, Leon E. Clarke*, and John P. Weyant**

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This special issue of the Energy Journal documents the main findings of Energy Modeling Forum Model Inter-comparison Project (MIP) number 24 (EMF 24) entitled "The EMF24 Study on U.S. Technology and Climate Policy Strategies." This study focused on the development and cross model comparison of results from a new generation of comprehensive U.S. climate policy intervention scenarios focusing on technology strategies for achieving climate policy objectives. These scenarios enabled the community to exercise enhanced modeling capabilities that were focused on in previous EMF studies on the international trade implications of climate policies; the representation of technological change; and the incorporation of multi-gas mitigation and land use emissions and mitigation policy alternatives.

This introduction has four objectives: (1) describe the motivation for the EMF 24 study, (2) put this study in the context of other past and current IAM inter-model comparison projects, (3) describe the structure of this special issue of the Energy Journal, and (4) give a brief overview of the insights developed in the papers produced by the individual modeling teams that are included in this special issue.

EMF 24 focused on the interactions between climate policy architectures and advanced energy technology availabilities in the U.S.. It followed on previous EMF climate change oriented Model Inter-comparison Projects (MIPs): EMF 12 on carbon emission limits (Gaskins and Weyant, 1993; Weyant, 1993), EMF 14 on carbon concentration limits (EMF 14, 1996; Haites, et al., 1997), EMF 16 on the costs and energy system impacts of the Kyoto Protocol (Weyant, 1999), EMF 19 on carbon constraints and advanced energy technologies (Weyant, 2002), EMF 21 on non-CO_2 Kyoto gas mitigation (de la Chesnaye and Weyant, 2006), and EMF 22 on climate control scenarios (focusing on phased participation in a climate mitigation coalitions and the possibility overshooting long run climate targets (Clarke, et al, 2009). As such, this study was able to take advantage of all the significant model extensions and enhancements that have taken place over the last twenty years.

EMF 24 itself was the outgrowth of a study started in April 2010 and was set up to include three parallel model comparison exercises at the global, US and European Union (EU) levels as had been the case in the EMF 22 study. As the work progressed, however, that study became too large, including too many people, models, (over forty models across the three domains) and interests to deal with efficiently in one large project and so the original project was split into three separate studies on constructing and interpreting the results of climate policy and technology scenarios at the global (EMF 27, Kriegler, Weyant, et al., 2013b), US (EMF 24, this volume) and EU levels (EMF 28, Knopf, et al., 2013). At the same time there was great interest in doing a new model comparison study on the international trade dimensions of climate policy (following on an earlier attempt in EMF 18, 2002) using a largely different set of (trade oriented) global models than those included in EMF 27, and a MIP focused on energy infra-structure transitions in Europe tied into

* The EMF 24 Steering Committee

the EMF 28 study. The trade interest lead to another working group which produced a trade oriented global model inter-comparison on leakage effects and border carbon adjustments (Boehringer, et al., 2012), and the latter lead to an extension of the EMF 28 scenario analysis focusing on infrastructure constraints and opportunities (von Hirchhausen et al., 2014). Thus, the reporting on this collective work is being communicated through five separate journal special issues.

Over the last ten years, there has also been a steady and extremely valuable increase in model comparison studies organized within the European Union and other parts of the world as well as a broadening of the types of exercises being conducted in the U.S. In fact, this trend, lead, in part, to the formation of the Integrated Assessment Modeling Consortium (IAMC, 2014) six years ago to coordinate this work and make the studies truly global in scope and participation. The IAMC has now matured to the point that it has formal charter, a scientific steering committee, an annual research conference, and a world wide web site (IAMC, 2014).

Early EU sponsored inter-model comparison studies included "The Innovation Modeling Comparison Project" (IMCP, Edenhofer, et al, 2006) which noted that in the first generations of global energy-economy modeling applied to climate change, emerging from the late 1980s roughly up until the mid 1990s, technology entered through a series of exogenous assumptions. In true 'top-down' models, supply side technologies were reflected in assumptions about the elasticity of substitution between generic carbon and non-carbon sources (if any), whilst an "autonomous energy efficiency improvement" (AEEI) parameter was often used to reflect an assumed degree of decoupling between GDP and energy consumption—a single, fixed parameter encompassing both structural change in the relationship between economy and energy and the development and diffusion of demand-side technologies. Another early EU model inter-comparison study was "The Economics of Low Stabilization Project" (Edenhofer, et al. 2010) explored the economics of very low targets for stabilization of atmospheric concentrations of GHGs in the atmosphere. The objective of the United Nations Framework Convention on Climate Change (UNFCCC) is "stabilization of greenhouse gas (GHG) concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (UNFCCC 1992, Article 2). Reaching the target of climate stabilization at no more than 2°C above pre-industrial levels by the end of this century—which is how the European Union (EU) interprets Article 2—is a historic challenge for humankind. To make it likely that this challenge will be met, greenhouse gas concentrations have to be limited to at no more than 450 ppm CO2 equivalent (for a 50 % likelihood) or below. The study showed that this goal requires a portfolio of mitigation options for very stringent emission reductions and requires taking globally coordinated action now.

A very important non-EMF, US based model inter-comparison study was Climate Change Science Program (CCSP) Product 2.1 (a). In the CCSP Product 2.1(a) study (Clarke, et al., 2007) actively involved each of three modeling groups—MERGE, MIT-IGSM, Mini-CAM in the model comparison process. The study produced one reference scenario and four stabilization scenarios, for a total of 15 scenarios. The reference scenarios were developed under the assumption that no climate policy would be implemented beyond the set of policies currently in place (e.g., the Kyoto Protocol and the U.S. carbon intensity goal, each terminating in 2012 because goals beyond that date have not been identified). Each modeling group developed its own reference scenario. The Prospectus required only that each reference scenario be based on assumptions believed by the participating modeling groups to be meaningful and plausible. Each of the three reference scenarios is based on a different set of assumptions about how the future might unfold without additional climate policies. These assumptions were not intended as predictions or best-judgment forecasts of the future by the respective modeling groups. Rather, they represented possible paths that the future might follow to serve as a platform for examining how emissions might be reduced to achieve stabilization.

Another more recent U.S based non-EMF Inter-Model Comparison study was the "The Asian Modeling Exercise (AME)." This was originally an outreach and capacity building oriented model comparison exercise sponsored by the U.S.E.P.A. the U.S.A.I.D., the EMF and several other groups. It was launched by Jae Edmonds, Leon Clarke and Katherine Calvin of the Joint Global Research Institute (JGCRI) at the University of Maryland and Pacific Northwest National Laboratory. It engaged a large number of global Integrated Assessment models and Asian country/ regional models in a comparison of baseline, carbon cap and carbon tax scenarios. A number of study groups were formed to interpret the model results in an innovative set of cross cutting papers: (1) base year data, (2) a base line projections, (3) urban and rural development, (4) low carbon societies, (5) technology, (6) regional mitigation comparability, and (7) national policies and measures. A special issue of *Energy Economics* documenting the results from this study was published in late 2012 (Calvin, Clarke and Krey, 2012).

There are also a number of ongoing EU and US sponsored climate policy oriented model inter-comparison projects that are finishing or producing interim results during 2013. These include the RoSE project (Luderer, et al. 2014), the LIMITS project, (Tavoni et al. 2014; Kriegler, et al. 2014b), and the AMPERE project (Kriegler et al. 2013a) co-ordinated within the European Union, as well as the PIAMDDI and LAMP projects in the United Sates. In the EU "**Ro**admaps towards **S**ustainable **E**nergy Futures (RoSE)" project," a set of low-stabilization scenarios under a policy target of limiting atmospheric greenhouse gas concentrations at 450 ppm CO2eq by 2100 are analyzed. For comparison, another set of stabilization scenarios with a less stringent policy scenario of 550 ppm CO2 eq reached at 2100 was considered. This study focuses on a deep and systematic exploration of the importance of various scenario drivers like economic growth projections, energy resource base assumptions, and energy conversion technologies between primary and final energy for achieving such targets (Luderer et al. 2014).

The **L**ow Climate **Im**pact Scenarios And The **I**mplications Of Required **T**ight Emission Control **S**trategies (LIMITS)" project is aimed at generating insight into how 2°C compatible targets can be really made implementable, including a heavy focus on financial flows (from country to country and industry to industry) and infrastructure required to convert today's energy systems to those reuired to achieve these targets in the future. This study is also examining the relationships between individual country or region action and global outcome (Tavoni, et al., 2014; Kriegler, Tavoni, et al., 2014b).

The EU sponsored "**A**ssessment of Climate Change **M**itigation **P**athways and **E**valuation of the **R**obustness of Mitigation Cost **E**stimates (AMPERE, Kriegler, 2014)" project explores a broad range of mitigation pathways and associated mitigation costs under various real world limitations, while at the same time generating a better understanding about the differences across models, and the relation to historical trends. Uncertainties about the costs of mitigation originate from the entire causal chain ranging from economic activity, to emissions and related technologies, and the response of the carbon cycle and climate system to greenhouse gas emissions. AMPERE is using a sizable ensemble of state-of-the-art energy-economy and integrated assessment models to analyse mitigation pathways and associated mitigation costs in a series of multi-model intercomparisons. It is focusing on four central areas: (i) The role of uncertainty about the climate response to anthropogenic forcing on the remaining carbon budget for supplying societies around the globe with energy, (ii) the role of technology availability, innovation and myopia in the energy sector, (iii) the role of policy imperfections like limited regional or sectoral participation in climate policy regimes, and (iv) the implications for decarbonisation scenarios and policies for Europe. This project is due to be completed by early 2014.

The U.S. Department of Energy sponsored "Program on Integrated Assessment Modeling Development, Diagnostic and Inter-Comparsions (PIAMDDI)," is an integrated assessment modeling (IAM) community research program on IAM model development; inter-comparisons and diagnostic testing; and multi-model "ensemble-like" analyses. The five cutting edge IAM research areas included in the program are: science and technology; impacts and adaptation; regional scale IA modeling; key intersecting energy-relevant systems; and uncertainty. The program is dedicated to improving the science of integrated assessment by doing cutting edge research in five critical areas of IAM development and integrating that research with a program of model inter-comparisons and ensemble-like activities. This program is linked closely to other climate change research programs in the U.S. and abroad . Progress on the scientific research areas is informing the model comparison and scenario ensemble tasks, and the comparisons and ensemble activities are helping set priorities for the research areas. Each research area as well as the model comparison and ensemble construction work is continually being broken down systematically, back down to fundamental first principals to help assess the state of the art and set focused priorities for the individual research efforts. A series of expert community workshops are facilitating this process. This project is due to be completed by the end of 2016 and is being closely co-ordinated with the EU sponsored AMPERE project described above.

The "Latin American Modeling Project (LAMP)" is a relatively new project patterned after the AME project but focusing on Latin American. This study was initiated by Katherine Calvin and Leon Clarke of the Joint Global Change Research Institute and is again sponsored by the U.S. Environmental protection Agency and U.S. Agency for International Development. A novel part of this study will be consideration of integrated climate change impacts assessment in major Latin American countries. LAMP is scheduled for completion by late 2014.

After this introductory piece, the wealth of results from the EMF24 study is presented in two layers in this volume. The policy and technology dimensions of the study are explored in greater depth in two separate overview papers (Fawcett, et al., 2014; Clarke, et al., 2014). In addition, nine of the 11 modeling teams that provided model results for this study developed individual modeling team papers, summarizing their experiences running the study scenarios and developing unique insights from the application of their individual modeling platforms. These insights are summarizing briefly here.

The papers produced by the individual modeling teams each produced a number of additional insights. A few of these are highlighted here and the reader is referred to the individual papers for more explanation and more insights. Using the NewERA model, Tuladhar, et al. (2014) show the extent to which broad based mitigation policies like an economy wide cap and trade system can lead to higher marginal costs an, but lower total costs, than sector specific regulatory policies like a Renewable Portfolio Standard (RPS) on electric power generation or Corporate Average Fleet Efficiency (CAFÉ) standard on automobiles. In reaching a similar conclusion with the CIMS model, Jaccard, et al. (2014) show that in some scenarios steep reductions focused only on the transportation sector can lead to almost completely off-setting increases in other sectors, leaving economy wide emissions almost completely unaffected and incurring substantial costs.

A number of modeling teams focused on limits and opportunities for rapid expansion and grid integration of intermittent renewable electricity generation technologies (principally wind and solar based). Two related major issues were addressed—the impact of regional disaggregation and grid integration constraints on renewables market penetration. Regional disaggregation of the renewable energy resource base generally leads to the isolation of higher quality wind resources which can make those resources mode competitive than would be the average quality resources over a larger geographical extent. Offsetting this in part is the increased requirement to back up renewals capacity as its share of total generation increases. Using the ReEDS model, Sullivan, et al. (2014) show how regional disaggregation of the renewables resource base can lead to a very large variation in renewables market penetration between geographical regions of the U.S. as well as larger overall nation-wide renewables generation. In addition, those calculations lead to the conclusion that, the ability to substitute renewables generations from regions where availability is low on a particular day leads to capacity value for renewables, meaning less back up power is required than would be the case of all renewables generation availability were independent. In an interesting parallel analysis using the ADAGE model, Ross, et al. (2014) shows a three to five percentage point reduction in renewables generation share across regions in a Renewable Portfolio Standard Scenario when using NREL/ReEDS specification for renewables availability and grid integration constraints.

Another set of renewables grid integration analyses are performed by Blanford, et al. (2014) using the U.S. REGEN model show the difference in electricity rate impacts between states where electricity rates are set in competitive markets and those where cost-of service regulation is practiced. For the lean Energy Standard scenario this analysis shows a larger rate increase in the cost or service regions on average owing to requirement maintain capital recovery payments to dirty generators in those regions.

In another interesting application of US REGEN (Blanford, et al., 2014) shows that a high natural gas availability/low natural gas price case actually leads to a slight increase in the cost of satisfying the Clean Energy Standard requirements as baseline energy system costs are lower with more inexpensive natural gas supplies.

Two models focused on international trade issues that could significantly influence domestic outcomes from the study scenarios. In an analysis with the GCAM model (Calvin, et al., 2014), the impact of restrictions on international trade in biofuels and use of forest lands to grow bio-fuels in the US or internationally is restricted. These alternative scenarios produce many interesting adjustments in biofuels, bio-fuels feedstock and crop production, including significant increase in U.S. crop and biofuel feedstock imports is a scenario targeted on an 80% reduction in US GHG emissions by 2050 with no bio-fuel imports permitted. In a somewhat more aggregated analysis, Sands, et al. (2014) using the FARM model show that, scenarios that target an 80% reduction in US GHG emissions, emission elsewhere in the world can be expected by 10–20% unless additional policy measures are implemented.

Finally in a very important analysis politically, Rausch, et al. (2014) using MIT's USREP model shows, calculating impacts on consumer equivalent variation by income decile, that the electricity policies considered in the study tend to be regressive, whereas the transport policies are progressive with the combination of the two turning out to be progressive for the scenarios considered in the study.

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Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise

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ABSTRACT

This paper presents an overview of the study design and the results of the EMF 24 U.S. Technology Scenarios. The EMF 24 U.S. Technology Scenarios engaged nine top energy-environment-economy models to examine the implications of technological improvements and technological availability for reducing U.S. greenhouse gas emissions by 50% and 80% by 2050. The study confirms that mitigation at the 50% or 80% level will require a dramatic transformation of the energy system over the next 40 years. The study also corroborates the result of previous studies that there is a large variation among models in terms of which energy strategy is considered most cost-effective. Technology assumptions are found to have a large influence on carbon prices and economic costs of mitigation.

Keywords: Technology, scenarios, climate change

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1. INTRODUCTION AND BACKGROUND

It is now well understood that technology cost, performance, and availability can have a substantial impact on the macroeconomic costs, and the challenge more generally, of meeting long-term global climate goals as well as national mitigation goals such as those that have been considered in the United States. Although a number of individual studies have specifically explored the role of technology in meeting climate goals in the U.S. (see, for example, Kyle 2009 and Kyle 2011 among others), there exists no coordinated study that explores this space across multiple models and using a coordinated set of model assumptions. The EMF 24 scenarios fill this gap. Nine models produced scenarios for this study, based on three mitigation goals for the United States: no emissions reductions (reference scenarios), a 50% reduction in emissions by 2050 relative to 2005 levels, and an 80% reduction relative to 2005 levels. These emissions pathways correspond to those explored in the EMF 22 multi-model study (Clarke et al., 2009) and its predecessor (Paltsev et al., 2008). The EMF 24 scenarios then combine these mitigation goals with various assumptions about the availability, cost, and performance of CO_2 capture and storage (CCS), nuclear power, wind and solar power, bioenergy, and energy end use.

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Table 1: Summary description of EMF 24 Technology Scenarios

Technology Dimension								
		Single Sensitivities			Combined Sensitivities			
	Opt Tech	Pess EE	Pess CCS	Pess Nuc	Pess Renew	Pess CCS/ Nuc	Pess EERE	Pess Tech
End-Use Energy	Opt	Pess	Opt	Opt	Opt	Opt	Pess	Pess
CCS	Opt	Opt	Pess	Opt	Opt	Pess	Opt	Pess
Nuclear	Opt	Opt	Opt	Pess	Opt	Pess	Opt	Pess
Wind & Solar	Opt	Opt	Opt	Opt	Pess	Opt	Pess	Pess
Bioenergy	Opt	Opt	Opt	Opt	Pess	Opt	Pess	Pess
Policy Dimension								
No New Policy (reference)	X	X	X	X	X	X	X	X
50% Cap & Trade	X	X	X	X	X	X	X	X
80% Cap & Trade					X	X		

Note: "Opt" refers to "Optimistic" and "Pess" refers to "Pessimistic." In the companion, policy paper (Fawcett et al., this volume), "Pess Renew" is referred to as "Opt CCS/Nuc", and "Pess CCS/Nuc" is referred to as "Opt Renew".

This study is motivated by three primary questions. First, how might technological improvements and technological availability influence the character of the U.S. energy system transition associated with 2050 climate mitigation goals? Second, what are the macroeconomic mitigation cost and carbon price implications of meeting 2050 climate mitigation goals, and how are these influenced by different futures of technology availability, cost, and performance? Finally, can 50% and 80% reduction goals for the United States be met largely through the implementation of limited technology portfolios? In particular, can these goals be met based exclusively through end-use measures and renewable energy—that is, without the use of nuclear power and CCS—and vice versa?

The remainder of this paper proceeds as follows. Section 2 introduces the study design for the EMF 24 Technology Scenarios. Section 3 then discusses the nature of the emissions and energy system transitions in the reference scenarios. Section 4 then discusses the economic, emissions, and technological characteristics of the mitigation scenarios. Section 5 sums up and discusses directions for future research suggested by the results of this study.

2. STUDY DESIGN

2.1 Overview of the study design

The EMF24 Technology Scenarios were designed to assess how the cost and availability of low-carbon technologies and energy end-use measures might affect the U.S economy and energy system under policies that reduce GHG emissions. The matrix of scenarios in the study consists of a technology dimension and a policy dimension (Table 1). The technology dimension captures

Table 2: Technology Assumptions

Technology	Optimistic Tech	Pessimistic Tech
End-use Energy	End-use assumptions that lead to a 20% decrease in final energy consumption in 2050 relative to the pessimistic technology, no policy case.	Evolutionary progress. Precise assumptions specified by individual modeling teams specified by each individual modeler.
Carbon Capture and Storage (CCS)	CCS is available. Cost and performance assumptions specified by individual modeling teams	No implementation of CCS.
Nuclear	Nuclear is fully available. Cost and performance specified by each modeling team.	Nuclear is phased-out after 2010. No new construction of plants beyond those under construction or planned. Total plant lifetime limited to 60 years.
Wind and Solar Energy	Plausibly optimistic technology development. Cost and performance assumptions specified by individual modeling teams.	Evolutionary technology development. Cost and performance assumptions specified by individual modeling teams
Bioenergy	Plausibly optimistic level of sustainable supply. Supply assumptions specified by individual modeling teams.	Evolutionary technology development representing the lower end of sustainable supply. Supply assumptions specified by individual modeling teams.

variations in technology cost, performance, and availability. The policy dimension captures the two 2050 mitigation goals for the study.

The suite of technologies examined in the study includes end-use energy reduction technologies, CCS, nuclear power, wind and solar power, and bioenergy. For each class of technologies, optimistic and pessimistic sensitivities were specified (Table 2). For nuclear power and CCS, the sensitivities are meant to capture the influence of factors that might affect the availability of these technologies. Hence, the pessimistic sensitivities restrict the deployment of these technologies whereas the optimistic sensitivities allow for expansion. No variation in cost and performance is assumed for these technologies. Based on similar reasoning, bioenergy sensitivities represent variations in the supply of bioenergy. In contrast, sensitivities for wind and solar power capture variations in the cost and performance of solar and wind power. No explicit limitations on expansion were specified for the scenarios. Finally, sensitivities in end-use are meant to capture changes in technology and deployment that would lower end-use energy demands. Because many models do not have structural representations of the end-use sector, the end-use assumptions were specified simply in terms of a reduction in final energy consumption. The means of achieving this reduction was left ambiguous, which raises interpretation issues that are discussed below.

The EMF 24 Technology Scenarios (Table 1) represent different combinations of technology sensitivities (Table 2). They are bracketed by Optimistic Technology and Pessimistic Technology assumptions, which hold all technologies at their respective optimistic and pessimistic sensitivities. A set of three single technology sensitivities test the effect of switching from optimistic assumptions about end-use, CCS, and nuclear to pessimistic assumptions while maintaining optimistic assumptions for all other technologies. Three combined sensitivities, Pessimistic CCS/Nuc, Pessimistic Renewable, and Pessimistic End-Use Energy and Renewable Energy (EERE) examine the effect of limiting the energy system transition to pathways that rely on particular combinations of technologies. Scenarios based on Pessimistic CCS/Nuc assumptions rely exclusively on end-use reductions and renewable sources, because deployment of CCS and nuclear energy is constrained.

Scenarios based on the Pessimistic Renewable assumptions assume the availability of CCS and nuclear energy, but uses less optimistic assumptions about renewable technologies. The Pessimistic EERE technology assumptions add pessimistic assumptions about end-use energy to the Pessimistic Renewable assumptions.

Several observations are important for interpretation of these scenarios. First, although the assumptions across technology categories were chosen to be roughly comparable, in practice this is an imprecise and subjective decision. It is difficult, for example, to assess the likelihood of the end-use energy reductions assumed in this study relative to the constraints on CCS or nuclear energy. Second, with the exception of nuclear and CCS assumptions, the precise of specifications of many of the technology assumptions (e.g., for renewable power) were left to the individual modeling teams, who undoubtedly chose different values. This means that it is difficult to consistently ascertain the implications of, for example, more optimistic wind and solar assumptions. One reason for this decentralized approach was that the models have very different methods of representing these technologies. Third, the costs of achieving Optimistic Technology assumptions are not specified for any of the scenarios. For example, research, development, and demonstration (RD&D) costs are not specified. This means that the cost difference between scenarios based on Pessimistic Technology and Optimistic Technology assumptions is biased toward overestimation in all cases by the additional investment that would be required to reach the Optimistic Technology assumptions. The treatment of end-use measures is particularly ambiguous in this regard. Improvements in end-use efficiency could involve a mix of both improvements in technology and changes in policy—for example, appliance efficiency standards—to spur adoption. The precise role of each of these is unspecified. To interpret the end-use assumptions in a manner that is consistent with the supply-side assumptions, it is necessary to assume that all of the energy end-use reductions occurred because of the availability of new technology with higher efficiency but without additional cost. In addition to the ambiguity of the source of end-use energy reductions, there are known market failures in markets for end-use efficiency that further complicate the welfare costs of implementing energy end-use measures.

All told, then, the differences in results arising from differences between technology assumptions in this study should be interpreted carefully and precisely. On the one hand, it is possible to draw some conclusions about the implications of different technologies at a broad level. On the other hand, these results are highly dependent on assumptions and may miss underlying costs, so precision is limited.

The policy dimension of these scenarios is based on an economy-wide carbon price leading to linear reductions in cumulative emissions of greenhouse gases over the period from 2012 through 2050. Reductions are specified as reaching either 50% below 2005 levels or 80% below 2005 levels in 2050. Banking of allowances is allowed, but borrowing of allowances is not permitted. In cases where models found banking to be cost-effective, the linear pathway was not sufficient to characterize the scenarios, so a cumulative total was required. The emissions cap covers all Kyoto gases in all sectors of the economy that the particular model represents, with the exception of CO_2 emissions from land use and land use change, which are excluded from the analysis. This means that non-CO_2 land use and land use change emissions and emissions of GHGs not covered under many U.S. climate bills are still included in the cap. It is important to note that different models have different capabilities to represent emissions from different sources and sectors (see Table 3), so individual models were asked to define the full scope of their targets to fit the capabilities of the models. In general, this meant that there was a distinction between those models that represent non-CO2 substances and those that don't.

The balance between the technology and policy dimensions of the study was made by conducting a full evaluation of technology variations for the 50% scenarios and then producing both 50% and 80% reductions for two specific combinations of technology assumptions. To manage the burden on the modelers, it was not feasible to produce the full range of technology variations for both the 80% reduction scenarios in addition to the 50% reduction scenarios. The two technology combinations chosen for the 80% scenario were chosen to explore the implications of (1) focusing the energy system solution largely on renewable energy and reductions in energy demand by specifying pessimistic assumptions for nuclear and CCS (Pessimistic CCS/Nuc) or (2) biasing the solution toward nuclear and CCS, along with reductions in energy demand, by specifying pessimistic assumptions for renewable energy while allowing for expansion of nuclear energy and CCS (Pessimistic Renewable). In both of these cases, optimistic assumptions were used in energy end-use to allow for a clearer comparison of the effects of the different supply-side options.

To define consistent policy architectures across the models, additional specifications were made in the areas of international emission reductions, bioenergy trade, offsets, and banking and borrowing. For global models, the rest of the world follows emission reduction paths that are similar to U.S. reductions in developed countries and considerably slower in developing ones. Trade in bioenergy is limited by design to isolate U.S. bioenergy activity. Domestic and international offsets were not allowed. The precise assumptions for the EMF 24 Scenarios, in the form of the final specifications presented to the participating modeling groups, are provided in the Supplemental Material for this paper.

2.2 Participating Models

Nine models participated in this study. These models differ in a number of ways that can have important implications for the resulting scenarios (Table 3). Models vary in their sectoral coverage, with the core sectors of interest being the energy sector, land use, and the rest of the economy. In general, models are designed to focus on breadth or on depth. For example, some models may represent only the energy or electricity sector and put substantial focus on capturing the details of that sector; others may represent the full economy with the focus on capturing the interactions between sectors. Models that represent the full economy are capable of producing a broader suite of economic indicators, including consumption losses and GDP effects. Models without a full economy typically represent costs in terms of area under the marginal abatement cost function or total system costs. Models vary in their regional resolution, with many models representing the U.S. as a single region, others representing roughly ten subregions, and one model representing over a hundred separate regions. The variation in covered gases, as noted above, influences how the models represented the mitigation targets. Some models represent all covered gases, whereas others focus only on CO2. Models capture the time dimension in different ways as well, including the last historical year in the model (the base year) and the time steps of the model (ranging from two years to ten years). It is important to note no model included a base year of 2012, which means that 2012 was a projection year in all of the models in this study. The representation of technology choice is one important factor in the way that models represent technology. Some models used probabilistic approaches to technology choice among discrete technologies, others use production functions, and still others use linear and non-linear optimization methods among discrete technologies. The models also vary in the way that they represent foresight. Models generally fall into two categories: dynamic-recursive models, which assume that all decisions are based on current conditions, and perfect foresight models which assume that decision-makers have

Table 3: Overview of Key Characteristics of the Versions of Participating Models Used in EMF 24.

Model	Covered Sectors	Number of US Regions	Covered Gases	Model Base Year	Model of Technology Choice	Model Time Step (years)	Last Model Year without Climate Policy	Intertemporal Solution Approach	Bio w/CCS	Citation for Paper in this Volume
ADAGE	Energy, Rest of Economy (Limited Land Use)	6	CO2, CH4, N2O, HFC, PFC, SF6	2010	CESproduction function	5	2010	Intertemporal Optimization	No	Ross et al. (2013)
CIMS	Energy	1	C02, CH4, N20	2005	Probabilistic choice model	5	2010	Recursive Dynamic	No	Jaccard and Goldberg (2013)
EC-IAM	Energy, Rest of Economy (no Land Use)	1	CO2,CH4, N2O, Short lived F-gases, long lived F-gases	2000	Linear/Non-Linear programming (Electric supply Sector, Non-Electric Energy Supply Sector); CESproduction function (Rest of Economy),	10	2010	Intertemporal Optimization	No	Zhu and Ghosh (2013)
FARM	Energy, Rest of Economy (no Land Use)	1	CO2	2004	CESproduction function	5	2009	Recursive Dynamic	Yes	Sands et al. (2013)
GCAM	Energy, Land use	1	CO2, CH4, N2O, HFC, PFC, SF6	2005	Logit choice model	5 (but 2012 is included as an addiitonal year)	2012	Recursive Dynamic	Yes	W ise et al. (2013)
NewERA	Energy, Rest of Economy (no Land Use)	1*	CO2	2008	Linear/Non-Linear Programming (Electric Supply Sector); CES Production Function (all Other Sectors)	5	2010	Intertemporal Optimization	No	Tuladhar et al. (2013)
ReEDS	Electric Supply	134	CO2	2010	Linear/Non-Linear Programming	2	2012	Sequential Myopic	No	Sullivan et al. (2013)
USREP	Energy, Rest of Economy (no Land Use)	12	CO2, CH4, N2O, HFC, PFC, SF6	2004	CESproduction function	5	2010	Recursive Dynamic	No	Rausch et al. (2010)
US-REGEN	Energy, Rest of Economy (no Land Use)	15	CO2	2010	Linear/Non-Linear Programming (Electric Supply Sector); CES Production Function (all Other Sectors)	5	2010	Intertemporal Optimization	No	Blanford et al. (2013)

* Note that at the time that the EMF 24 runs were produced, NewERA included only a single U.S. region. The current default version includes 12 U.S. regions.

a complete view of the future when they make decisions. One model applies a combination of these two, with limited foresight. Finally, the option to deploy CCS with bioenergy is an important technology for these scenarios, because it can lead to negative emissions. Mot models assume that this technology will not be available.

3. ENERGY, TECHNOLOGY, AND EMISSIONS IN THE REFERENCE SCENARIOS

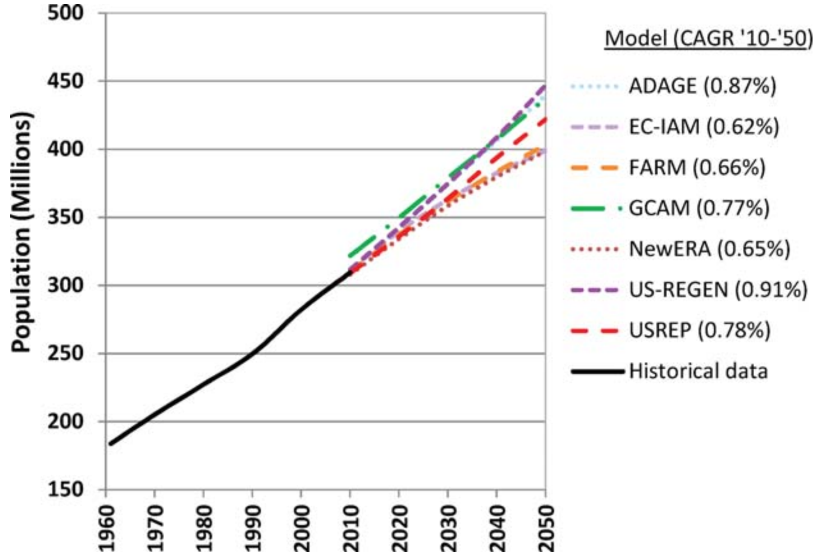
Reference (or no policy) scenarios serve several roles in studies such as this. One role of reference scenarios is that they serve as a counterfactual starting point for the application of policies. It is therefore important to understand the nature of the reference scenarios as a basis for insight in the behavior of the mitigation scenarios, which are the focus of this study. Differences in reference scenarios can lead to differences in the characteristics of mitigation pathways. For example, higher emissions in the reference scenario will require greater emissions reductions in the mitigation scenarios. Another role of reference scenarios is to provide a window into the uncertainty surrounding key drivers—for example, population growth, economic growth, and resulting emissions and energy pathways—that influence the behavior of the mitigation scenarios. Different modeling groups develop different estimates of the drivers of emissions. The fact that assumptions and reference results vary among groups derives from our collective lack of knowledge about how these key forces might evolve forty years into the future. The variation in reference assumptions and results, however, are not a full representation of uncertainty, particularly since modeling teams may base their projections of key parameters on common sources of projections. Nonetheless, they still provide some insight into our lack of knowledge about the future (see Krey and Clarke, 2011 for more on this topic). A third role of the reference scenarios in this study in specific is that they provide insights into the impact of technology on energy demand and emissions in the absence of an explicit climate policy.

3.1 Population and GDP

One of the main determinants of future energy demand and emissions is population growth, which correlates both to the supply of labor and the demand for goods and services (Figure 1). The population projections used in the models assume that the US population will add between 89 and 138 million people by 2050. The associated compound annual growth rates from 2010 to 2050 range from 0.6 to 0.9 percent per year. All of these assumptions are below population growth in the U.S. over the last 40 years, which stood at an annualized rate of 1 percent. These population projections are not characterized by substantial variation; all fall within $+/-5$ percent of the mean value of 420 million in 2050. All other things being equal, this lack of significant variation in the population estimates would tend to dampen variation in key characteristics of the mitigation scenarios, such as policy costs. For comparison, the population projections are roughly bounded by population estimates from the United Nations (UN) and the US Census Bureau. For the lower bound, the UN, in its medium variant case projects the US population at 400 million in 2050 (UN 2009). At the upper end, the US Census Bureau's 2050 projection is 439 million, which is close to the UN's high variant case (US Census 2008).

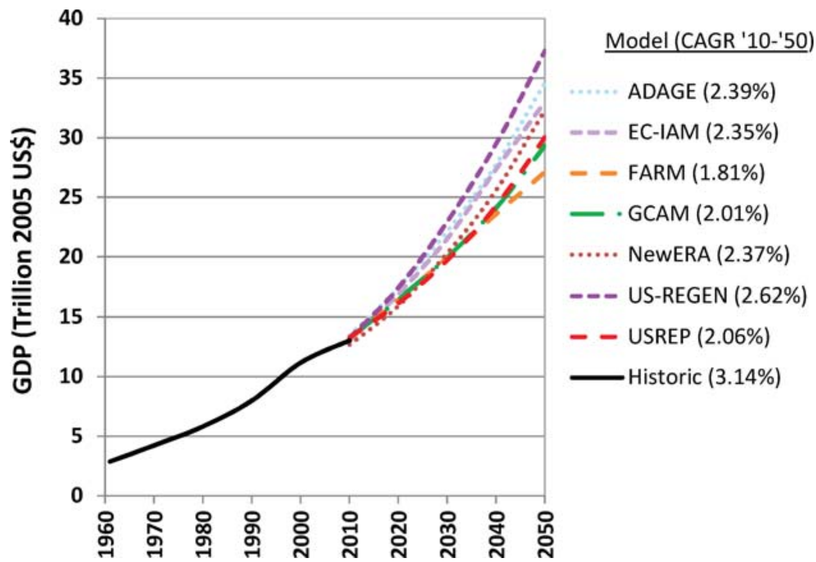
The level of economic activity, as measured by gross domestic product (GDP) (Figure 2), is a major driver of energy consumption. GDP can be an explicit input to models or it can be calculated within the models. However, even in the latter case, GDP is primarily driven by two or three primary input assumptions, including labor force, labor productivity, and technological change, and is generally implicitly calibrated to expectations. This means that reference GDP lies

Figure 1: Population assumptions across models



Note: CAGR refers to cumulative annual growth rate.

Figure 2: GDP projections across the models, Optimistic Technology reference scenario



Note: CAGR refers to cumulative annual growth rate.

somewhere between an input assumption and a model result even in models in which it is calculated endogenously. Changes in GDP from policy or technology changes, in contrast, are an important output of many models.

The compound annual growth rates across the models from 2010 to 2050 are between 1.8 and 2.6 percent under the Optimistic Technology assumptions. These growth rates are slower than

Table 4: Percentage change in reference scenario GDP relative to the reference scenario with Optimistic Technology assumptions in 2020 and 2050

	2020				2050			
	Pess. Renew	Pess. CCS/ Nuc	Pess. EERE	Pess. Tech	Pess. Renew	Pess. CCS/ Nuc	Pess. EERE	Pess. Tech
ADAGE	0.0	0.0	−0.3	−0.3	0.0	0.0	−1.2	−1.2
EC-IAM	0.0	0.0	−0.1	−0.1	0.0	−0.1	−0.5	−0.8
FARM	0.0	0.0	−0.7	−0.7	0.0	0.0	−1.7	−1.7
NewERA	0.0	0.0	0.1	0.1	0.0	0.0	0.4	0.3
US-REGEN	0.0	0.0	−1.0	−1.0	−0.1	0.0	−2.2	−2.2
USREP	0.0	0.0	−0.5	−0.5	0.0	0.0	−1.9	−1.9

historical rates. The annual GDP growth rate in from 1950–1990 was 3.5 percent and declined to 3.1 percent from 1967 to 2007. Across the models, the growth rates tend to fall by up to a few tenths of a percent each decade. GDP shows a greater degree of variation than population across the models. By 2050 the average GDP across model projections reaches $32 trillion with a spread of $10 trillion, or +/−17 percent of the mean.

Of particular interest for the discussion here is that GDP can be influenced by technology assumptions for the "general equilibrium" models participating in this study—those that represent the full economy (Table 4). The particular end-use energy assumptions used in this study have the largest influence on reference GDP. Although tempting, it is not possible, given the structure of the study, to conclude that energy use technologies are more valuable in the absence of carbon policy than supply technologies. A primary reason for this is that there is no cost associated with achieving the assumed level of energy use improvements (roughly 20% reduction), nor is there clarity on the associated issue of whether they occurred purely through the availability of new technology or by end-use-focused policies. (See Section 2.1 for a more thorough discussion of interpretation of technology assumptions).

At the same time, it is clear that more optimistic assumptions of the low-carbon energy supply have only a limited influence on GDP in the reference scenarios. Their effects are felt most strongly in the presence of a price on carbon. Without a price on carbon, there is little incentive to increase the deployment of these technologies substantially enough to dramatically alter the energy system (see Section 3.2) and influence GDP.

3.2 Energy Consumption

Consistent with the discussion of GDP effects, the particular assumptions about energy end-use in this study have a larger effect on total primary energy demand and total electricity demand in the reference scenarios that does the variation in energy supply technology assumptions (Figure 3 and Figure 4). As noted previously, this result is largely a matter of construction, since the optimistic end-use assumptions were constructed explicitly to result in roughly a 20% reduction in energy demand relative to the Pessimistic Technology reference case (see Section 2.1). The different modeling teams produced these assumptions in different ways, so that the actual variation between the Optimistic Technology and Pessimistic Technology reference scenario demands ranges across models from between 8% and 24%.

Figure 3: Total primary energy consumption (direct equivalents) in reference scenarios in 2050 by source and technology assumptions

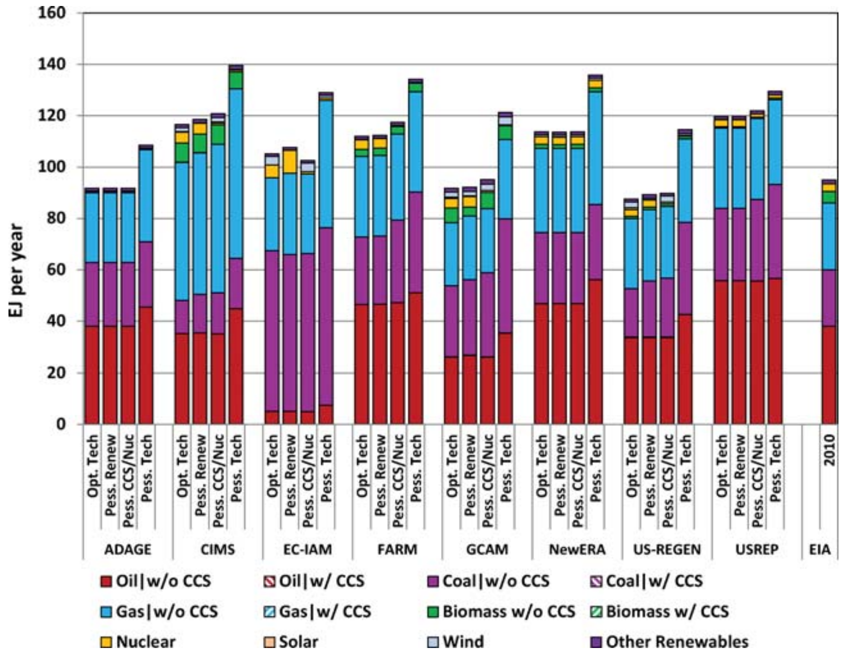
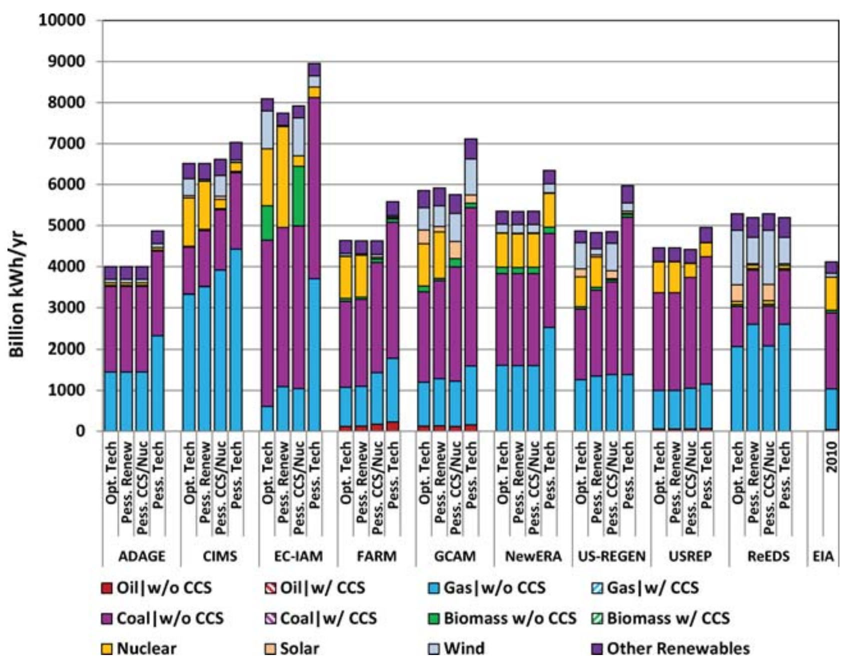


Figure 4: Electricity generation in reference scenarios in 2050 by technology assumptions



The effects of the energy supply assumptions follow intuition in terms of direction. Not surprisingly, the Pessimistic Renewables assumptions lead to less renewables than the corresponding Optimistic Technology assumptions, and the Pessimistic CCS/Nuc assumptions lead to less nuclear than the corresponding scenarios with Optimistic Technology. Because the accounting of primary energy is conducted in direct equivalents rather than primary equivalents in Figure 3, less optimistic technology assumptions lead to an increase in primary energy in many of the scenarios. This is simply an artifact of the fact that the pessimistic technology assumptions lead to less nuclear and renewable electricity, which is replaced by fossil fuels. With direct equivalent accounting, fossil electricity represents higher primary energy than nuclear and renewable electricity.

More generally, a notable characteristic of all the reference scenarios is that fossil fuels continue to dominate the energy system, and the electricity system in specific, even under the more optimistic technology assumptions. None of the models indicate that these assumptions will be sufficient to bring about the changes necessary to reduce emissions on the order of 50% or 80% as explored in this study. In addition, the mix of fossil fuels is more dependent on the model and its attendant assumptions than on the assumptions that were employed to capture different levels of low-carbon supply technology. That is, particular models tend to lead to a particular mix of fossil fuels that remains similar across technology assumptions. Both the quantity of fossil energy and the mix of fossil energy are fundamental to the determination of reference scenario CO_2 emissions. All other things being equal, models with higher quantities of coal lead to higher emissions. Of interest, few models project a dramatic expansion of natural gas in the scenarios. One might expect an evolution in reference scenarios produced over the coming years by the models in this study toward natural gas if U.S. gas potential and production continues to play out at the scales that are being suggested.

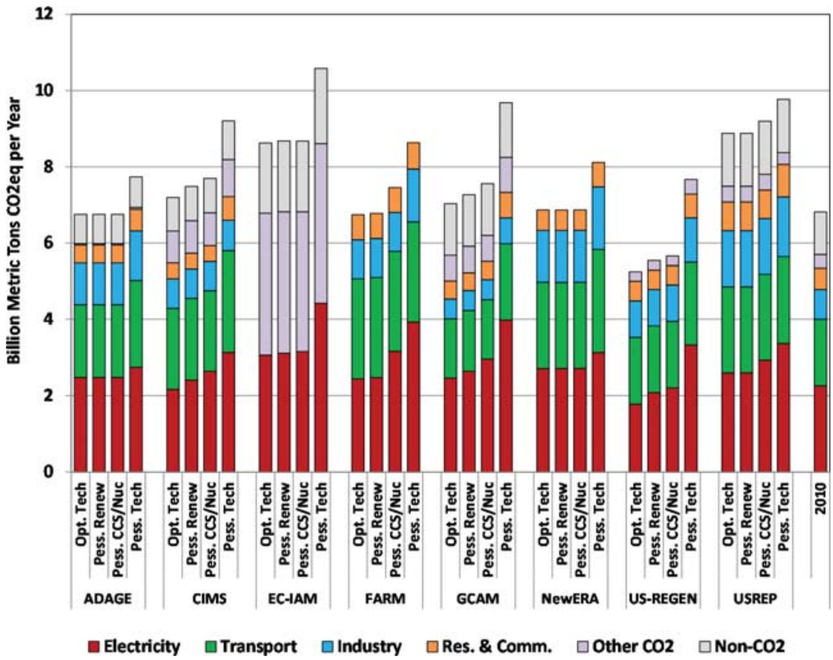
3.3 Greenhouse Gas Emissions

Consistent with the lack of low-carbon penetration into the energy sector discussed in Section 3.2, no reference scenario in this study meets the mitigation goals of the study. Even under Optimistic Technology assumptions, the most aggressive emissions reduction from any of the models is -0.19% per year through 2050 (Figure 5 and Figure S.1 in the supplementary material for this paper). Although self-evident, this observation is important because it further reinforces the notion that it is unlikely that technology alone will be sufficient to meet aggressive climate goals. Climate policy is needed to reduce emissions in a meaningful way. In the results from this particular study, the benefit of technology is largely to alter the challenge of meeting long-term mitigation goals.

The variation in reference scenario emissions tends to follow the variation in energy production quite closely, and therefore follows the same logic. That is, the end-use assumptions have the largest influence on reference scenario emissions, and there is substantial variation across models in terms of reference scenario emissions. Although not shown here, the variation in supply technology assumptions does not lead to as large a variation in emissions as the variation in the models and their attendant assumptions. The electricity and transportation sectors together account for over half of total emissions by 2050 in all models, as is the case today (Figure 5). This is an artifact of the fact that the building sector and the industrial sector both make extensive use of electricity, which means that much of the emissions consequences of these sectors are mediated through electricity production.

In addition to the different sizes and characters of the energy systems across models and scenarios, one reason for variation in 2050 among the models is that they begin at different starting

Figure 5: GHG emissions in reference scenarios in 2050 by sector and by technology assumptions



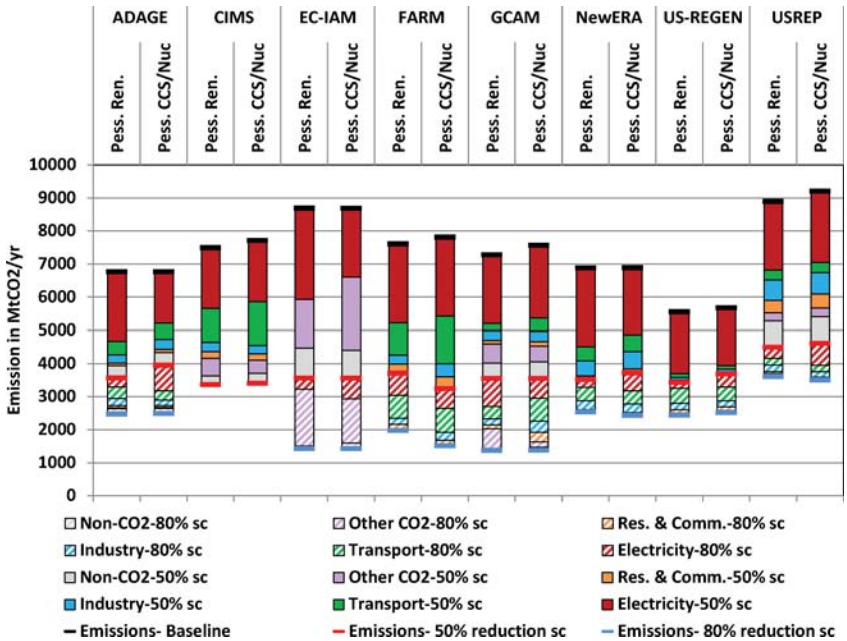
points in 2010. A large portion of the variation is due to differences in the gases covered by the different models. Those models that track only CO2 emissions fall well below those that track additional GHGs. A second reason for the difference is that models start from different points in time (see Table 3), so that 2010 is a projection year for all models in this study. In general, none of the models effectively represented the recent reduction in CO2 emissions.

4. CLIMATE POLICY SCENARIOS

4.1 Emissions pathways and the feasibility of emissions reductions targets

A broadly important result of the mitigation scenarios is that every model could produce every scenario in the study. This means that they were able to meet 50% reductions even under the most pessimistic assumptions about technology. It also means that every model was able to produce the 80% reduction scenarios without nuclear and CCS; that is, relying exclusively on renewable energy and end-use measures. Conversely, every model could produce all mitigation the scenarios based on less optimistic assumptions about renewable energy. To be clear, however, this ability of models to produce scenarios is not sufficient to draw conclusions about the "feasibility" of these scenarios in a more applied sense. The ability or inability of models to produce scenarios is a useful input to discussions of feasibility. However, judgments of feasibility are ultimately bound up in subjective assessments of whether the U.S. (in this case) would be willing and capable of taking on the transformation required to meet the mitigation goals, including bearing the associated macroeconomic costs and undergoing the required technological, institutional, and social transitions.

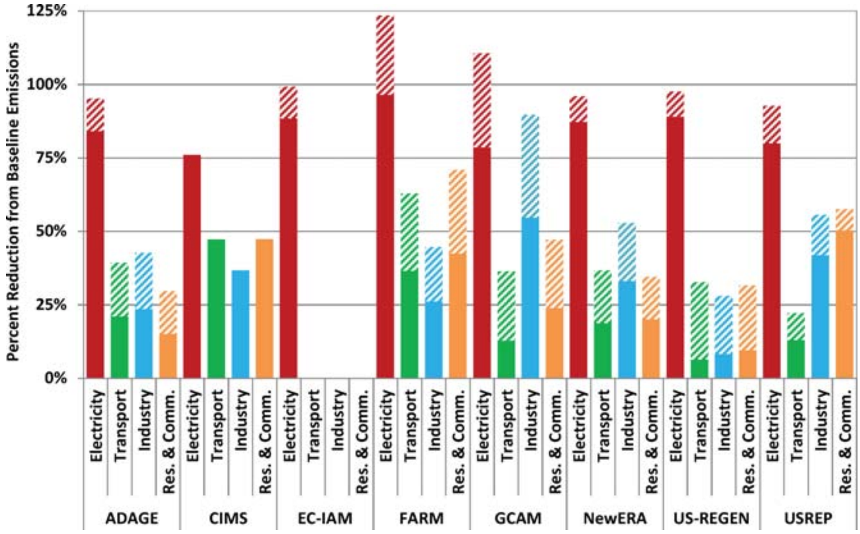
Figure 6: Emission reductions from the corresponding reference scenario in 2050 by sector in 50% and 80% scenarios for Pessimistic CCS/Nuc and Pessimistic Renew technology assumptions



Three important questions regarding mitigation are (1) from which sectors will emissions reductions come from in an economically-efficient approach to mitigation, (2) which sectors might undergo the largest transitions, and (3) which sectors might ultimately prove the most challenging for mitigation. The relative distribution of emissions reductions across sectors (Figure 6 and Figure 7) provides a window into these questions. Across scenarios, electricity constitutes the largest single contributor to emissions mitigation across models, and electricity undergoes a substantial transformation through 2050. For example, most models reduce electricity by 75% or more by 2050 in the 50% reduction scenarios under Pessimistic Renewable assumptions. The role of electricity in these scenarios supports the notion that electricity is the least-challenging sector to decarbonize directly so it takes on the largest initial emission reductions (see, for example, Edmonds et al., 2006). However, it is also important to remember that not all these reductions arise from changing to low-carbon supply options. In many models, the price on carbon also leads to reductions in electricity use in end uses, which lowers electricity sector emissions (technology transitions in the electricity sector are discussed in Section 4.3).

Because emissions from electricity are so substantially reduced in the 50% scenarios, there is relatively little remaining room for additional emissions reductions from that sector to meet the 80% goal in most models. For this reason, the bulk of the additional emissions reductions come from non-electric sectors, which require increasingly higher costs. Exceptions to this include FARM and GCAM, which rely upon bioenergy coupled with CCS in the electric sector. With this technology, the electric sector serves as a carbon sink moving from the 50% to the 80% scenario; that is, emissions are reduced beyond 100%. This limits the necessity to reduce emissions from other sectors at deeper levels of emissions reduction. Under the Pessimistic CCS/Nuc assumptions, ADAGE, NewERA and USREP also find additional, substantial reductions from the power sector.

Figure 7: Direct emissions reductions in 2050 by sector under Pessimistic Renewables assumptions.



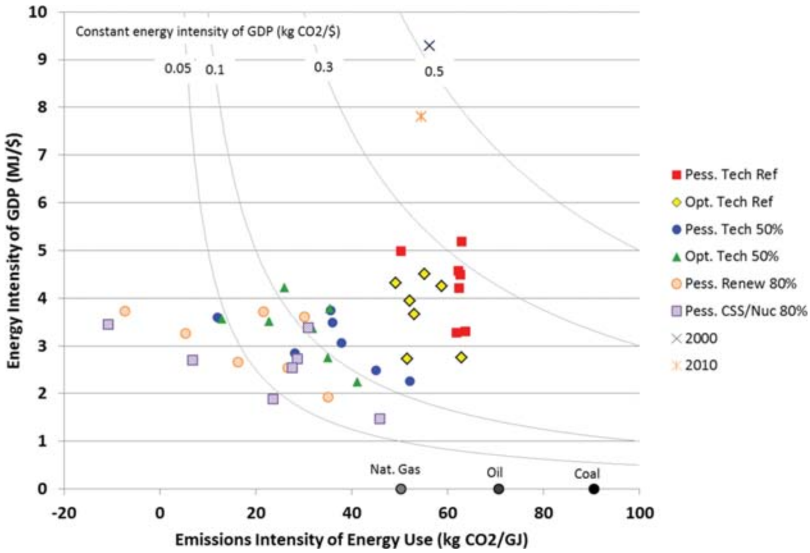
Solid bars represent sectoral reductions for the 50% cap; hashed bars represent the additional reductions for the 80% cap.

A salient question for understanding the strategy for mitigation in the U.S. is whether mitigation in the energy sector takes place more through reductions in the emissions intensity of energy or reductions in the energy intensity of GDP. The relationship between these provides a perspective on the relative roles of end-use energy reduction (associated with the change energy intensity of GDP) and the deployment of low-carbon energy and fuel switching to better utilize lower carbon fuels (reflected in the change in emissions intensity of energy). Historically, evolution in the energy sector over the last fifty years largely involved reductions in the energy intensity of GDP, with only modest reductions in the carbon intensity of energy (Figure 8 and Figure S2 in the Supplementary Material). The reference scenarios continue this trend, exhibiting a decline in the energy intensity of economic activity from about 8 MJ/$ today to between 3–5 MJ/$ in 2050 with very little change in the emissions intensity of energy over this time.

This behavior is largely reversed in the mitigation scenarios. The primary means of additional emissions reductions is to alter the mix of primary energy. Under Pessimistic Technology and Optimistic Technology assumptions with a 50% emissions reduction, the energy intensity falls to 2–4 MJ/$. Emissions intensity of energy consumption declines from roughly 60 kgCO2/GJ to between 20 and 50 kgCO2/GJ. To put those numbers in the context of fossil fuels, the average carbon content of energy consumption would be similar to natural gas and up to roughly 50% lower.

In addition to affecting emissions pathways across sectors and energy and emission intensities, technology availability also alters the emission reductions pathways over time (Figure S3 and Figure S4 in the Supplementary Material). The effect of technology on banking behavior is of particular interest. Recall that the cumulative reduction targets are based on a straight-line emissions pathway. The ability to bank emissions lowers overall policy costs by equalizing the marginal reduction costs over time. A bank of emission permits is built in the near-term when the policy target is less stringent and marginal reduction costs are lower. As the emissions constraint becomes more stringent over time and marginal reduction costs rise, banked permits are used to meet part

Figure 8: Energy intensity of GDP vs. emissions intensity of energy in 2050 (fossil equivalents) for different technology assumptions and emissions reduction levels



of the reduction target. The level of banking differs substantially across models. However, banking is greater across all of the models under Pessimistic Tech assumptions than under Optimistic Technology sssumptions. With fewer low-cost mitigation options in the future, the models rely more heavily on near-term reductions as a strategy to lower overall costs. Banking is also greater in the 80% reduction scenarios than in the 50% reduction scenarios.

4.2 Technology and the costs of mitigation

The costs of mitigation are influenced not only by the mitigation goals, but also by the technologies available for mitigation. One common economic indicator of cost is the price of carbon at different points of time (Figure 9). An important caveat in interpreting the carbon price is that it is not an actual metric of total costs. It gives only the marginal cost, and depending on the shape of the marginal abatement costs function, the variation in prices with different levels of mitigation could be very different than the variation in total costs. Measures of economic impacts that are more reflective of total costs include effects on economic output or mitigation cost expressed as consumption loss, equivalent variation, or area under the marginal abatement cost function (Figure 10 and Table S1, Figure S5, and Figure S6 in the Supplementary Material). Models have different capabilities to calculate these various metrics, so an assessment of costs generally must include different metrics across models.

It is important to note that all of these cost metrics are influenced by the presence or absence of other policies. For example, the presence of regulatory policies to reduce energy consumption will lower the carbon price below what it would be in the absence of these additional policies. It will also lower the total costs of mitigation if the costs of these additional policies are not included in the total cost calculations. A proper cost accounting should take into account the costs of these additional policies as well (see Fawcett et al., 2014, this volume for a further discussion of the implications of combining carbon prices with other policy measures). The interpre-

Figure 9: Emission prices across models and scenarios in 2020 (top panel) and 2050 (bottom panel)

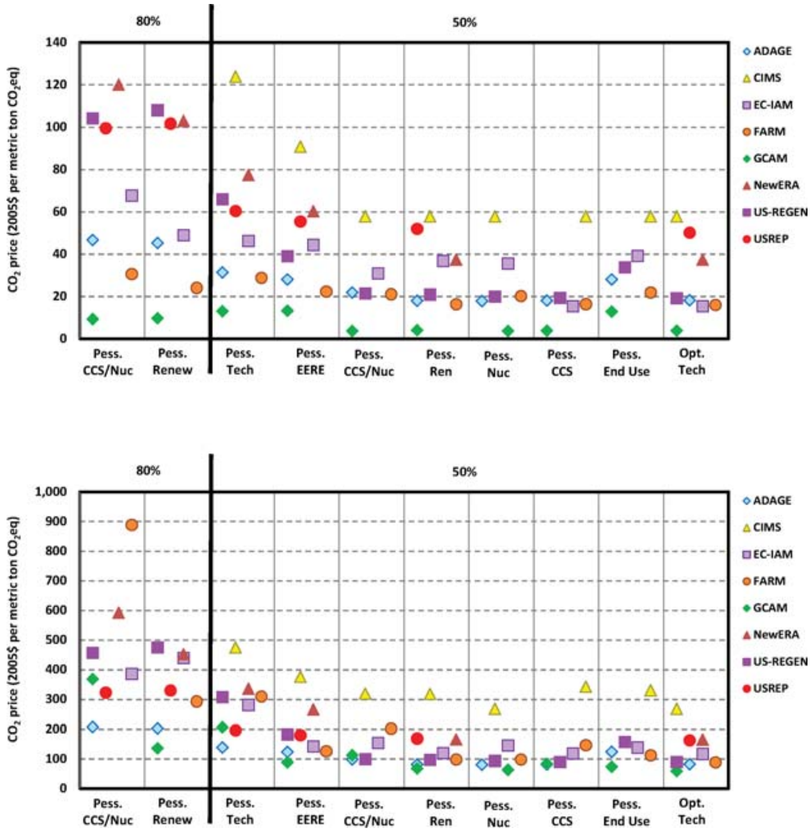
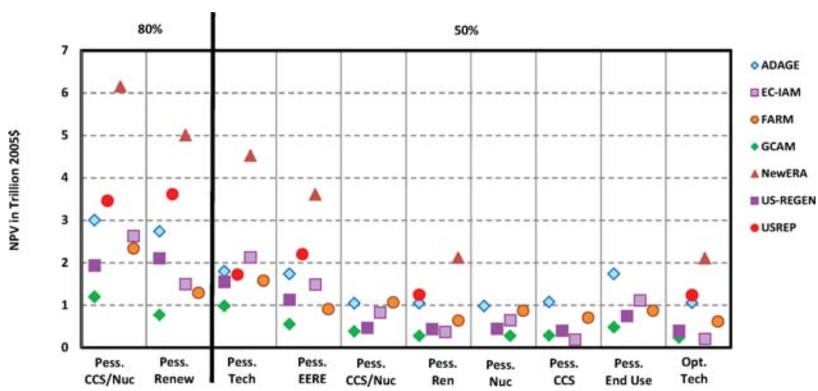


Figure 10: Net present value of mitigation costs from 2010 to 2050



tation of the difference between scenarios with pessimistic end-use assumptions and those with optimistic end-use assumptions is particularly ambiguous in this regard. Because the means of obtaining these end-use reductions is not specified, the change in the carbon price and the total cost metrics associated with the different levels of end-use technology may not be reflective of the full cost of those scenarios. If the improvement in end-use technology is assumed to result exclusively from improvements to technology, as opposed to policies that lead to their deployment, then cost metrics will be reflective of the total impact of obtaining these energy reductions. (Note, as well, and as discussed in Section 2.1, that the costs of improving technology, for example through R&D, are not included in any of the results presented here and also that there are a range of market failures in markets for technology adoption in end-uses that make interpretation of cost implications of end-use policies challenging.) More broadly, the issue of complementary policies is relevant to all scenarios in this study to the extent that existing policies, such as building standards and CAFE standards, are already in place and influencing energy demand. The cost metrics in this study reflect only the costs in addition to those from policies already in place.

These caveats notwithstanding, several insights emerge from the scenarios. First, the models provide very different estimates of both prices and costs, and this variation across models is larger than the variation in costs within models and across technologies. The variation in economic metrics across models is an outcome of every multi-modeling study to date (see, for example, Calvin et al., 2012, Clarke et al., 2009, and Clarke et al., 2007, among others). It has proven challenging to disentangle the relative roles of model structure and model assumptions in leading to this variation. Diagnosing the reasons for the substantial differences in the economic indicators from models more generally is an important area of continuing research. What is clear from this study is that controlling for several key technology assumptions, such as limiting the deployment of nuclear power and CCS, is not sufficient to obtain convergence in model estimates of costs.

That said, for the 50% reduction scenarios, and under the most pessimistic (most optimistic) assumptions about technology, carbon prices in 2020 fall between \$20/tCO2 and \$80/tCO2 (\$10/tCO2 and \$40/CO2) in most models. As a comparison, the carbon prices in 2020 for a similar 50% reduction policy target in the EMF 22 study (Fawcett et al., 2009) were between \$25/tCO2 and \$70/tCO2. The net present value of economic costs through 2050 under the most pessimistic (most optimistic) assumptions about technology fall between \$1 trillion and \$2 trillion (less than \$1 trillion) in most models. GDP in 2050 is reduced by between 2% to 4% (0.5% to 1.5%) below what it would otherwise be in most models that produce this metric under the most pessimistic (most optimistic) assumptions about technology. For the 80% scenario with either Pessimistic CCS/Nuc assumptions or Pessimistic Renewable assumptions, carbon prices in 2020 in most models fall between \$20/tCO2 and \$120/tCO2, total mitigation costs through 2050 fall between \$1 trillion and \$4 trillion, and GDP is 3% to 5% lower than it would otherwise be.

Given the variation in absolute costs among models, it is useful to explore how costs change within models across technology assumptions and mitigation goals as a way to understand the relative importance of different technologies in the mitigation portfolio (Figure 11 and Figure 12). Moving from the Pessimistic Technology portfolio to the Optimistic Technology portfolio reduces carbon prices associated with meeting a 50% goal by roughly 20% to 70%; it reduces the total costs of meeting a 50% constraint by about 20% to over 90%. Moving to the 80% reduction goal increases carbon prices costs substantially.

At the levels of reduction considered in this study and with the models used in the study, there does not appear to be any clear technological winner among the different options. Removing nuclear energy, removing CCS, or taking on less optimistic assumptions about renewable energy all have comparable effects on costs, depending on the model. To a large degree, this reflects the notion that there are multiple options for mitigation in the electricity sector, the most important sector for mitigation in the 2050 window, particularly in the 50% scenarios, as discussed above, so

Figure 11: Emissions prices across scenarios in 2020 relative to prices under Pessimistic Technology assumptions and for a 50% emissions reduction

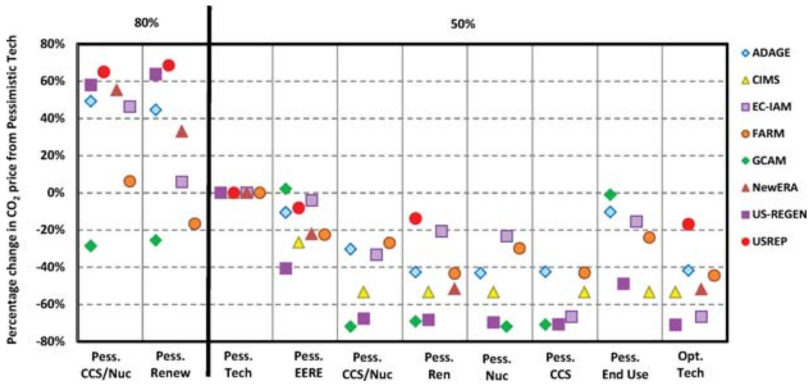
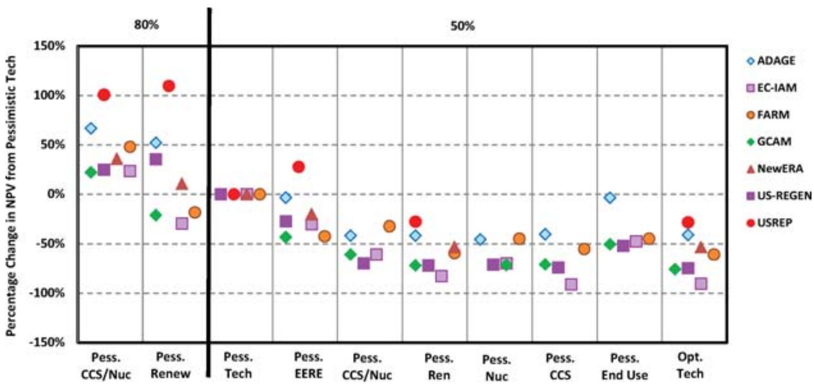


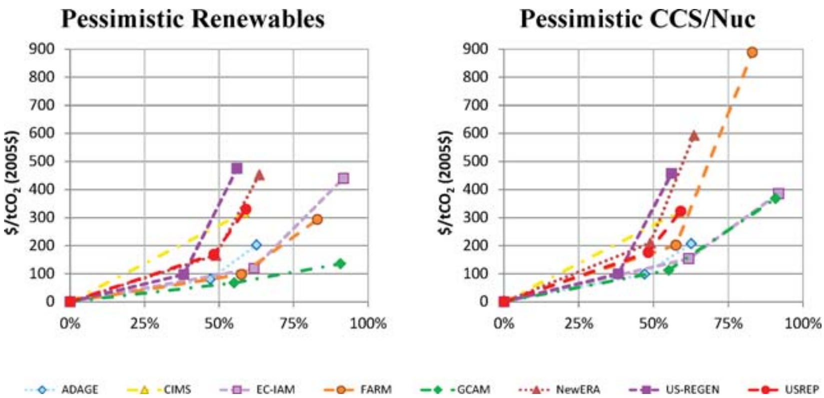
Figure 12: Percent change in NPV of mitigation costs relative to costs under Pessimistic Technology assumptions and for a 50% emissions reduction



the removal of any single option can be made up for by bringing more of other options on line. This result could be different were the study design to call for even deeper reductions than it does. For example, there is evidence that bioenergy coupled with CCS is a disproportionately valuable technology for global mitigation scenarios leading to ambitious goals such as 450 ppmv CO2-e by allowing concentrations to exceed ("overshoot") the long-term goal. These scenarios require extraordinarily deep and rapid emissions reductions in the second half of the century (see, for example, Clarke et al., 2009).

One of the key factors that might influence mitigation costs is the level of emissions in the reference scenarios. Higher emissions in reference scenarios require deeper reductions to meet the goals in this study, because these goals are expressed relative to 2005 rather than relative to reference scenario emissions. This behavior can be partially visualized in the context of marginal abatement cost functions (Figure 13; see also the companion paper, Fawcett et al., this volume for more on this topic). In general, the scenarios indicate that reference scenario emissions have an important influence on the carbon prices and associated costs of abatement, in the trivial sense that for any given model, larger reductions are associated with larger prices. However, the variation

Figure 13: Emissions prices in 2050 relative to percentage emissions reductions from the reference scenario under Pessimistic Renewable and Pessimistic CCS/Nuc technology assumptions



The first dot for each line represents emissions reductions and prices for the 50% reduction scenario. The second dot represents the emissions reductions and prices for the 80% reduction scenario.

among models in ability to reduce emissions is of far larger concern. For example, under Pessimistic CCS/Nuc assumptions, the model with the highest reduction from reference emissions in the 80% scenario has only the fourth highest carbon price associated with meeting the target. There is substantial variation in carbon prices for any given level of reduction from reference scenario emissions.

4.3 Technology and the evolution of the energy system

Mitigation will potentially require a substantial scale-up in low-carbon energy from today's levels (Figure 14 and Figure 15). The degree of scale-up depends heavily on the size of the energy system in the reference scenario and the degree of energy reductions in the mitigation scenarios. On the higher end of this spectrum, the amount of low-carbon energy by 2050 is upwards of 4 times today's levels for the 50% and the 80% reduction goals. On the other end of the spectrum, with substantial demand reductions, low-carbon energy is kept at roughly 2010 levels in 2050, even in the 80% reduction scenarios. It is important to note that the scenarios with lower low-carbon energy deployment levels are all scenarios with roughly 50% reductions or more in primary energy consumption relative to reference scenarios without the Optimistic Technology assumptions for energy end-use, with one scenario reaching roughly 75% reductions in primary energy consumption.

In general, the presence of CCS and nuclear energy leads to somewhat higher primary energy on a direct equivalent basis than is the case without these technologies and more optimistic assumptions about renewable power. However, as with economic costs, the largest different between scenarios is generally among models rather than among scenarios within a model. Some models rely heavily on end-use reduction, whereas others rely more heavily on low carbon energy. Two models rely heavily on the use of bioenergy coupled with CCS to produce negative emissions. Not surprisingly, without CCS or new nuclear power, scenarios rely more heavily on renewable energy. Conversely, with CCS and nuclear power, but with less optimistic assumptions about renewable energy, the scenarios rely more heavily on CCS and nuclear power. Consistent with previous studies

Figure 14: Primary energy consumption in 2050 in the 50% and 80% reduction scenarios for Pessimistic CCS/Nuc and Pessimistic Renewable technology assumptions

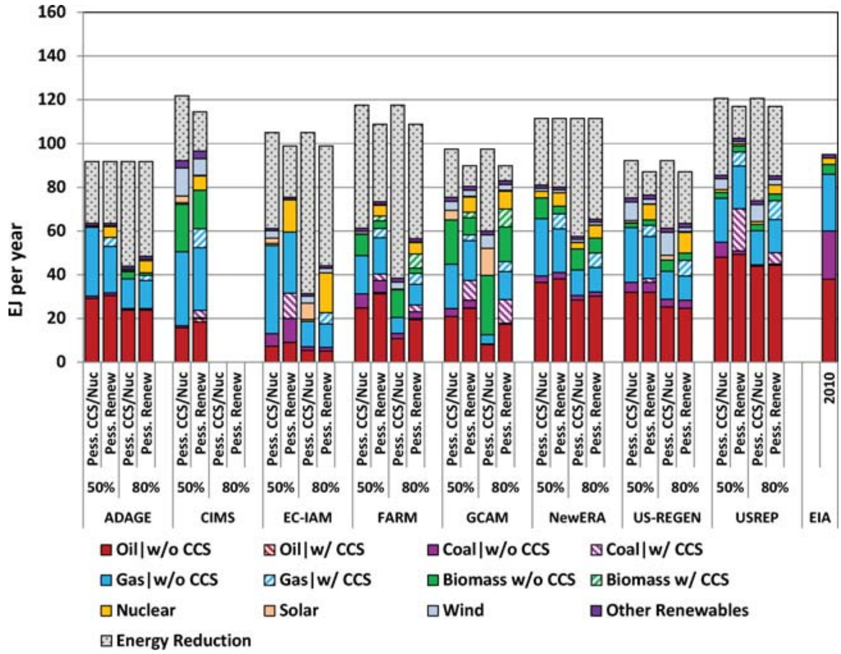
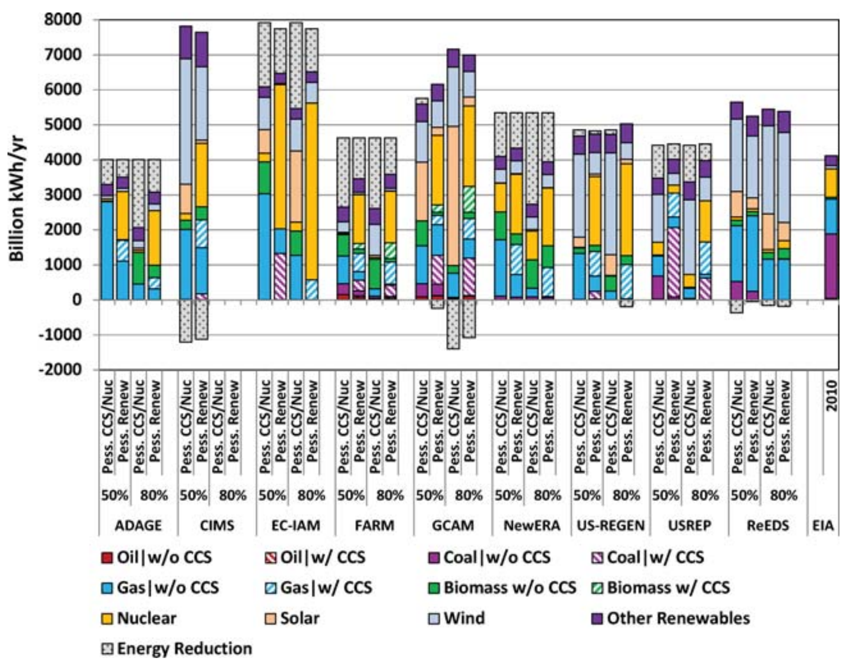


Figure 15: Electricity Generation in 2050 in the 50% and 80% reduction scenarios for Pessimistic CCS/Nuc and Pessimistic Renewable technology assumptions



(Edmonds et al., 2006), several studies find that mitigation increases electricity production as low-carbon electricity substitutes for liquid, solid, and gaseous fuels in end-uses.

More generally, the variation in energy system response among models reaffirms two important characteristics of our understanding of energy system responses to climate mitigation. The first is that there are many different pathways that can lead to the same long-term mitigation goal. The second is that there is sufficient uncertainty about technology and relative mitigation potential among sectors that modelers can come to very different conclusions. Key areas where modelers have made different choices include the ability to switch fuels in end-uses, the options for energy use reductions including both reductions in service and the potential for improved efficiency, the relative costs and performance of supply technologies, the manner in which intermittent technologies can be incorporated into the grid, and societal perceptions regarding specific technologies such as nuclear power. Many of these assumptions are explicit in assumptions about technologies or elasticities that are entered into the models, but others are more implicit in the structures of the models or the parameters that result from their calibration or constraints that are entered into the models. It was beyond the charter of the EMF 24 study to attempt to collect this information; however, more sophisticated diagnostics of the representation of technology is an important area for future research.

It is also important to emphasize that these models are searching for a pathway that will minimize the costs of mitigation. One hypothesis is the different pathways, as represented within any single modeling framework, may not have costs that are all that different; that is, there is a flat optimum. To some degree this hypothesis is confirmed by the fact that modest changes in the set of available supply-side technologies—say between the Pessimistic Renewable and Pessimistic CCS/Nuc assumptions—did not result in dramatic changes in the costs of abatement or the carbon price in many models. If the competition is close between technologies, then other societal priorities (e.g., energy security, local environmental concerns) may have an outsized influence on the precise choice of energy system configuration (Clarke et al., 2012, Krey et al., 2013).

5. CONCLUSIONS

The EMF 24 scenarios were motivated by the goal of exploring the implications of technology on the energy transitions and the macroeconomic costs of mitigation in the U.S. They were also motivated by the question of whether it is possible to achieve aggressive mitigation goals, such as an 80% reduction in emissions by 2050, using only limited technology portfolios. All told, the scenarios generally confirm a range of insights that are not necessarily new to this study: costs will be higher with fewer available technologies; a large-scale transformation of the energy system will be needed to meet long-term climate goals; the variation in costs and energy system configurations among models can be larger than the variation across scenarios; the electricity sector accounts for a disproportionate percentage of fossil and industrial emissions reductions over the next fifty years; and there is a wide variety of technology pathways for meeting long-term mitigation goals. As with many things, the devil is in the details with regards to emissions pathways, mitigation costs, and the energy system transformations, and these are provided in a range of figures and tables in this paper and the supplementary material, as well as the database for the study which is available online.

Beyond these generic insights, we would like to highlight three themes about technology and the interpretation of modeling results that emerge from the study. First, we find that there is no clear conclusion about whether one energy production technology is of more value than the others for the 50% reduction scenarios. There are several important reasons for this. For one, there was a large emphasis on electricity generating technologies in this study. Given the breadth of possibilities to produce low-carbon electricity, limitations on any single option can be overcome by using other options. However, for deeper reductions or longer-term scenarios, this particular behavior could break down. In particular, the ability to use bioenergy with CCS has been shown to be more valuable than other technologies in many studies where even deeper emissions reductions, including moving the entire economy to negative emissions, are required (see, for example, Krey et al., 2013). But with a focus only through 2050, this does not prove to be the case.

Second, even without limitations on particular technologies, the models assume very different energy system configurations for meeting the mitigation goals in this study. This is not a new result, but it remains an important one for understanding the role of studies such as this in articulating the "right" pathway to mitigation. To some degree this variation is simply a matter of our lack of understanding of the potential availability, cost, and performance of technologies in the future. On the other hand, it also supports the hypothesis that the competition between different configurations is tight—different configurations may have similar macroeconomic implications. This, in turn, highlights the fact that economics will not be the only deciding factor in which energy technology system we ultimately might rely on should the U.S. choose to substantially reduce greenhouse gas emissions. The fact that the costs of mitigation were largely unaffected by the removal of any single production technology corroborates this general result. Instead, other factors might exert the largest influence on the choice of the power system configuration. These might include energy security concerns, related environmental concerns such as those associated with nuclear waste or CO2 storage or even the effects of wind power on bird populations, or regulatory challenges in implementing important infrastructure, such as new transmission lines for renewable energy or a CO2 pipeline infrastructure.

Third, this paper has focused heavily on supply side technology solutions, and particularly on those associated with electric power. Yet, end-use technologies may be at the heart of many transformation pathways for climate mitigation. This goes beyond simply end-use energy reductions, which was the focus of the end-use component of this study. Opportunities for fuel switching may be a critical determinant of future energy system configurations. For example, improvements in batteries could lead to the widespread use of electricity in transportation, which is often considered to be the hardest sector to decarbonize. Even with end-use reductions, there are very broad questions about the potential for reductions, the welfare implications of reductions, and the relative implications of price-based and regulatory approaches to achieving end-use reductions. We would therefore like to encourage future studies to move beyond the focus on supply side options and toward a treatment not just of energy use reductions, but also of the possibility for changes in the types of fuels that we use at the end-use and the associated technologies.

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Overview of EMF 24 Policy Scenarios

Allen A. Fawcett, Leon E. Clarke**, Sebastian Rausch***, and John P. Weyant*****

ABSTRACT

The Energy Modeling Forum 24 study included a set of policy scenarios designed to compare economy wide market-based and sectoral regulatory approaches of potential U.S. climate policy. Models from seven teams participated in this part of the study assessing economy-wide cap-and-trade climate policy and sectoral policies in the transportation and electric sector in terms of potential greenhouse gas emissions reductions, economic cost, and energy systems implications. This paper presents an overview of the results from the U.S. policy scenarios, and provides insights into the comparison of results from the participating models. In particular, various metrics were used to compare the model results including allowance price, the efficient frontier, consumption loss, GDP loss, and equivalent variation. We find that the choice of economic metric is an important factor in the comparison of model results. Among the insights, we note that the carbon price should cautiously be considered when other non-cap sectoral policies affecting emissions are assumed in tandem. We also find that a transportation sector policy is consistently shown to be inefficient compared to an economy-wide cap-and-trade policy with a comparable level of emissions reductions.

Keywords: Climate policy, Energy-economy modeling, Sectoral climate policies, Policy interaction

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1. INTRODUCTION

In the absence of comprehensive legislation to curb greenhouse gas (GHG) emissions in the United States, policymakers have been pursuing climate change mitigation through sector or technology-specific regulatory measures. Comprehensive climate policies would cover most or all sources of GHG emissions and potentially incentivize reductions at least cost through a market mechanism—such as a carbon tax, cap-and-trade system, or hybrid mechanism—by achieving an equalization of marginal abatement costs across participants (Metcalf, 2009). Sectoral and regulatory measures, by contrast, require that GHG emissions reductions be achieved through compliance with sector-specific technology or efficiency targets. The policy scenarios of the EMF 24 exercise are based on combinations of three different types of national policy instruments: an economy-wide

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cap-and-trade policy, a transportation policy representing a Corporate Average Fuel Economy (CAFE) standard for light-duty vehicles (LDV), and a clean or renewable energy standard for electricity. These policy scenarios do not reflect any specific legislative or administration policy proposals, but instead are intended to represent more generic versions of economy wide and sector specific policies. Questions that are addressed are: (1) what are the potential implications of transportation and electric sector regulatory approaches to emissions reductions that are roughly consistent with widely discussed goals for the reduction of greenhouse gas emissions? (2) How do the separate regulatory policies behave on their own, and how do they interact with an economy-wide climate policy meant to meet this goal? (3) What are the costs of different policy architectures? (4) How might technological improvements and technological availability influence the answers to the above questions?

The EMF 24 study explores these questions through a comparison of results from seven modeling teams across seven standardized climate policy scenarios. Each modeling team was required to provide results related to economics, emissions, and energy systems for reference and policy scenarios. Policy assumptions are combined with two sets of coordinated technology assumptions for each individual or group of technologies: one set with pessimistic-technology assumptions representing *evolutionary* improvements in a technology, and a second set of optimistic-technology assumptions representing *plausibly optimistic* improvements. Modelers were free to make their own decisions on demographics, baseline GDP growth and energy consumption, and technology availability.

The remainder of this paper proceeds as follows. Section 2 details the study design and includes a list of modeling teams and scenarios. Section 3 and 4 provide results from the study on emissions pathways and the cost-effectiveness of climate policies considered here, as well as an exploration of differences in results across models and various cost and emissions metrics. Section 5 summarizes the results.

2. OVERVIEW OF THE STUDY DESIGN

2.1 Scenario Design

The scenarios in this study are built from combinations of technology assumptions and policy assumptions. Table 1 summarizes the scenarios. The "Technology Overview of EMF 24" (Clarke et al., 2013) in this volume describes the technology assumptions used in this study, and the policy assumptions are described below. Two of the policy assumptions, the baseline and the 50 percent cap-and-trade scenarios, are run for all of the technology assumptions, and are further explored in Clarke et al. (2013). This paper explores the full set of policy assumptions, which are modeled for two specific sets of technology assumptions, a "optimistic CCS / nuclear" set of technology assumptions that allow carbon capture and storage (CCS) and Nuclear technologies, and have pessimistic assumptions about renewable energy (RE); and a "optimistic RE" set of technology assumptions that do not allow CCS, phase out nuclear power, and have optimistic assumptions about bioenergy, wind and solar.[1] Both of these sets of assumptions include optimistic assumptions about end use technology.

1. For example, pessimistic CCS assumptions allow no implementation of the technology; pessimistic nuclear assumptions allow no new construction of nuclear power; conversely optimistic assumptions for nuclear and CCS specify that the technologies are available but the cost and performance characteristics are the modeler's choice.

Table 1: EMF 24 scenario matrix

Technology Dimension								
	Optimistic	**Single Technology Scenarios**				**Combined Sensitivities**		**Pessimistic**
End Use Technology	Optimistic	Pessimistic	Optimistic	Optimistic	Optimistic	Optimistic	Pessimistic	Pessimistic
CCS	Optimistic	Optimistic	Pessimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Pessimistic
Nuclear	Optimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Pessimistic	Optimistic	Pessimistic
Wind & Solar	Optimistic	Optimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Optimistic	Pessimistic
Bioenergy	Optimistic	Optimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Optimistic	Pessimistic
Policy Dimension								
Baseline								
0% Cap & Trade								
10% Cap & Trade								
20% Cap & Trade								
30% Cap & Trade								
40% Cap & Trade								
50% Cap & Trade								
60% Cap & Trade								
70% Cap & Trade								
80% Cap & Trade								
CAFE								
RPS								
CES								
CAFE + RPS								
CAFE + RPS + 50% C&T								

Seven policy architectures are explored in this study: (1) baseline or reference scenarios with no policy, (2) cap-and-trade scenarios of varying stringency, (3) combined electricity and transportation regulatory scenarios, (4) electricity and transportation regulatory scenarios combined with a cap-and- trade policy, (5) isolated transportation sector policy scenarios, (6) isolated electricity sector policy scenarios with a renewable portfolio standard (RPS), and finally (7) isolated electricity sector policy scenarios with a clean energy standard (CES). Each of the scenarios is described by the set of policies of which it is comprised. These are discussed in detail in Table 2.

2.2 Modeling Teams

Though nine models participated in the EMF24 study, seven modeling teams participated in the full extensive menu of policy scenarios of the EMF 24, and the results of these models are the focus of this paper. The models include: the Applied Dynamic Analysis of the Global Economy model (ADAGE), from Research Triangle Institute; the Environment Canada Integrated Assessment Model (EC-IAM), from Environment Canada; the Future Agricultural Resources Model (FARM), from U.S. Department of Agriculture; the Global Change Assessment Model (GCAM), from the Pacific Northwest National Laboratory/Joint Global Change Research Institute; the NewERA model, from NERA Economic Consulting;; the U.S. Regional Economy, GHG, and Energy Model

Table 2: EMF 24 policy assumptions

Policy	**Description**
Reference	The reference scenario assumes no climate policy. It does, however, include, to the extent they can be modeled by the participating modeling teams, any existing energy or related policies that might influence GHG emissions.
***XX%* Cap & Trade**	This represents the assumption of a national policy that allows for cumulative greenhouse gas emissions from 2012 through 2050 associated with a linear reduction from 2012 levels to *X* percent below 2005 levels in 2050, where *X* is the percentage reduction target associated with the scenario. The cumulative emissions are based on the period starting from, and including, 2013 and through 2050. With the exception of CO_2 emissions from land use and land use change, the cap covers all Kyoto gases (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6) in all sectors of the economy that the particular model represents. This includes non-CO_2 land use and land use change emissions and emissions of GHGs not covered under many U.S. climate bills. CO_2 emissions from land use and land use change are not included in the cap. For models that do not operate on annual time steps, the first year with a positive price on carbon is after 2012 (e.g., 2015 in a model with 5-year time steps), but the cumulative emissions are still be based on an assessment of the emissions associated with a linear path starting from, and including, 2013 and through 2050. Banking of allowances is allowed, but borrowing of allowances is not permitted. Note that the 0, 50 and 80 percent cap-and-trade scenarios are modeled closely after the EMF 22 U.S. transition scenarios (Fawcett et al., 2009).[a]
Renewable Portfolio Standard (RPS)	The RPS applies only to the electricity sector. In this context, renewable energy includes all hydroelectric power and bioenergy. The RPS is defined as 20 percent by 2020, 30 percent by 2030, 40 percent by 2040, and 50 percent by 2050. Banking and borrowing are not allowed. If modelers were unable to meet these requirements within their model, they were allowed to create a scenario that includes a less aggressive RPS, but one that can be met by the model.
Clean Electricity Standard (CES)	This policy is similar to the RPS, but also includes nuclear power, fossil electricity with carbon capture and storage (credited at 90 percent), and natural gas (credited at 50 percent) in the portfolio. Both new and existing generation from all eligible generation types may receive credit. Because many additional sources are allowed to receive credit, the targets are defined as linearly increasing from reference levels in the first year of the policy (the first model time-step after 2012) to 50 percent by 2020, 60 percent by 2025, 70 percent by 2030, 80 percent by 2035, 90 percent by 2040, and constant thereafter (note that the current share of clean energy in the U.S., as defined here, is 42.5 percent). Banking and borrowing are not allowed. All other characteristics are identical to the RPS.
New Coal CCS	This policy requires that all new coal power plants capture and store 90 percent or more of their CO_2 emissions.
Transportation Sector Policy	The transportation policy is a CAFE standard for light-duty vehicles (LDV) that specifies a linear increase in fuel economy of new vehicles, starting in 2012, to 3 times 2005 levels in 2050. If modelers do not have the ability to represent a CAFE policy, they can alternatively represent the policy as a cap that covers all LDV in the transportation sector, as defined in the particular model. This alternative policy is defined as a linear reduction in LDV emissions from 2012 levels to 55 percent below 2010 levels in 2050. Banking and borrowing are not allowed. It is understood that with rebound effects and differences in reference scenario, this LDV emissions cap policy structure will not be identical to the CAFE policy; however, we expect them to be similar (the 55 percent reduction in LDV emissions under the cap is consistent with the emissions reductions achieved in a test run of GCAM), and there are benefits to explicit analysis of CAFE standards. Note that biofuels, electricity, and hydrogen are assumed to be zero-emissions fuels for calculating the emissions cap.
Cap & Trade + Sectoral Policy	Combines the 50 percent cap-and-trade policy with the RPS, the new coal CCS requirements, and the transportation policy described above.[b]

[a] It should be noted that in principle a cap-and-trade program is equivalent to a carbon tax for which the tax trajectory over time is set such that the same emissions reductions are achieved each year. There are, however, various advantages and disadvantages for each policy instrument (for a discussion, see, for example, Metcalf, 2009).

[b] It should be noted that combining sectoral or regulatory policies with a cap-and-trade policy is not equivalent to combing them with a carbon tax. Sectoral or regulatory policies combined with a quantity based emissions target do not change the amount of emissions reductions, but instead change the way in which those reductions are achieved, which generally lowers allowance prices, but increases overall costs. When these complementary policies are combined with a carbon tax, they increase the total amount of abatement achieved under any particular carbon tax (see Fawcett et al. 2013 for further discussion).

(US-REGEN), from the Electric Power Research Institute; and the U.S. Regional Energy Policy (USREP) model, from the MIT Joint Program on the Science and Policy of Global Change. These seven models were able to report policy cost metrics that are the focus of the analysis presented here.[2]

2.3 Limitations of this Study

It is important to note some of the limitations of this study. First, while these scenarios comprise a broad set of different climate policies and span a wide range emissions reductions targets, many uncertainties have yet to be explored, and implementation details, such as permit allocation, cost containment mechanisms, and revenue recycling issues, were not addressed in the comparisons. Some, but not all, of these uncertainties have been addressed by modeling teams in their individual papers. Second, fully harmonizing technology cost assumptions across all models proved inherently difficult as there are significant differences in model structure, in particular with respect to how technology choice is represented in each model. Third, models have not been fully harmonized with respect to their representation of the U.S. fiscal system, in particular if and how they represent existing taxes (for example, income and payroll taxes, corporate income tax). This implies that the interaction of a given climate policy instrument with pre-existing fiscal (tax) distortions may differ across models. More generally, it should be noted that the rank-ordering of policy instruments depends significantly on how the rents from a cap-and-trade program are used. While we assume a per-capita based lump-sum recycling of the revenue, it is well-known from the literature (for example, Goulder et al., 1999) that using the carbon revenue to lower pre-existing distortionary taxes may yield substantial efficiency gains. Due to model differences in the representation of the fiscal system, this study is not able to explore this dimension further, but it is important to bear in mind that the estimated cost for the cap-and-trade policies presented below should be interpreted as an upper bound, i.e. cost may be smaller if the carbon revenue would be recycled by lowering marginal tax rates, and the welfare ranking vis-à-vis the regulatory policy choices may be altered. Fourth, the scenario design and model baselines were locked down in early 2012, so the baselines do not reflect policies that were later adopted (e.g. the light duty vehicle and corporate average fuel economy standards that were published in October 2012). Additionally, developments in energy markets such as the shale gas boom have altered baseline emissions projections since the EMF 24 scenarios were developed (e.g. the Energy Information Administration's Annual Energy Outlook (AEO) for 2013 projects 2020 CO2 emissions to be 6 percent lower than the then current AEO 2011 projections). Despite the various limitations and uncertainties, clear insights emerged from this study.

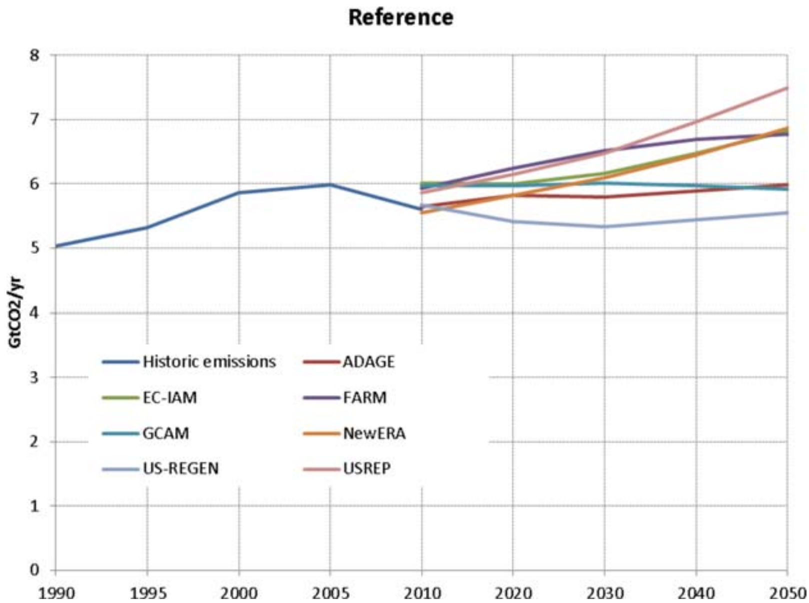
3. EMISSIONS PATHWAYS

Figure 1 shows historic U.S. CO_2 emissions covered by the policies modeled and projected reference scenario emissions for each model.[3] The reference case emissions pathways show a wide

2. The two other participating models were the Canadian Integrated Modeling System (CIMS), from Simon Fraser University; and the Regional Energy Deployment System (ReEDS) model, from the National Renewable Energy Laboratory. These models were not able to generate the policy cost metrics that are the focus of this paper.

3. Covered CO_2 is used here as the emissions variable for measuring cumulative reductions because several models do not include the non-CO_2 gases. Additionally, only the GCAM model includes CO_2 emissions from land use and land use change that differentiate covered CO_2 and total CO_2.

Figure 1: Historic and projected reference emissions–covered CO_2—(Optimistic CCS/ Nuclear)

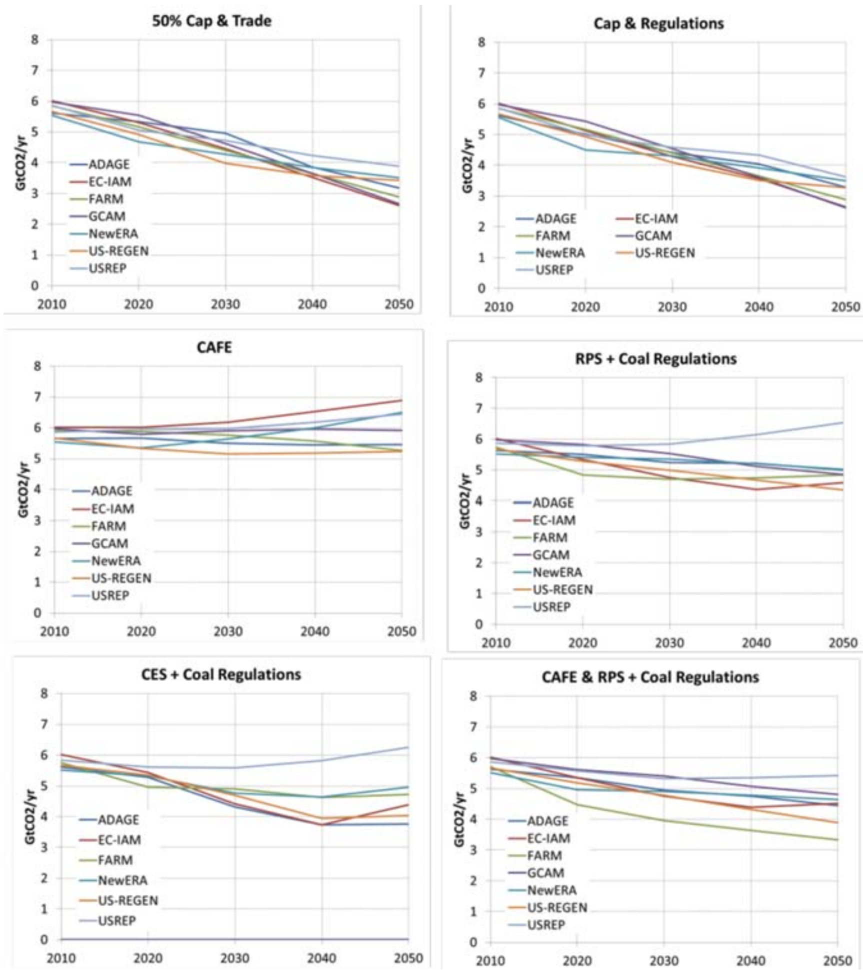


range of emissions projections across models, which is likely an important factor in explaining differences in costs among the participating models. Differing levels of emissions in the reference case imply different amounts of abatement required to meet the cap established in the cap-and-trade policies and the reductions targets implicitly specified in the sectoral regulatory approaches. Note that for most models, 2010 is a modeled year, and thus different input assumptions across models give rise to modest deviations from historic emissions in 2010. For a first group of models (US-REGEN, ADAGE, and GCAM) total U.S. CO_2 emissions in the reference case remain relatively flat over the 2010–2050 period while a second group of models models (USREP, NewERA, EC-IAM, and FARM) predict that emissions rise at roughly similar and constant rates reaching levels in 2050 that are 3–29 percent higher than emissions in 2010. Modeling teams in the first group expect significant reductions in carbon emissions per dollar of gross domestic product (GDP) even without focused climate policy, reflecting different baseline assumptions about recent and anticipated non-climate related regulatory policy changes, future energy prices, and economic growth as compared to the second group of models.

Figure 2 shows total U.S. covered CO_2 emissions in the six policy cases over time.[4] The emissions pathways in the 50 percent cap-and-trade are more similar across all of the models than the pathways in the reference case, as all of the models face roughly similar, but not identical, cumulative targets. While the 2050 endpoint of allocation of allowances is identical for all models, each model starts from a slightly different point in 2012 due to differences in projected reference case emissions. Differences in pathways for covered CO_2 emissions in the scenarios involving a cap-and-trade policy also arise because targets are formulated in terms of greenhouse gases, and

4. This and all subsequent graphs showing scenarios that involve the CES do not report outcomes from the GAM model as this policy was not modeled in GCAM.

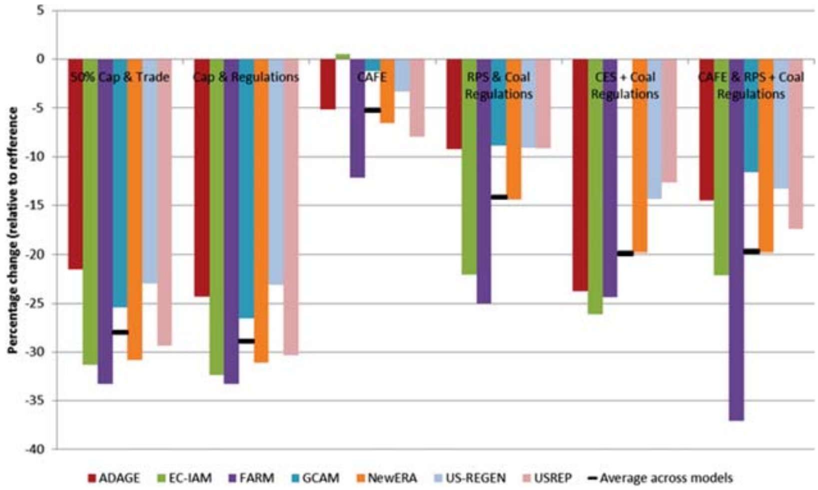
Figure 2: Emissions pathways –covered CO_2—(Optimistic CCS/Nuclear)



not all models include the non-CO_2 gases. Moreover, the models produce different inter-temporal allocations of allowances reflecting differences in terms of assumptions about cost and availability of new low-GHG technologies, and capital adjustment costs and the rate of capital stock turnover. Lastly, some models assume perfect foresight (ADAGE, NewERA, US-REGEN, and EC-IAM), in combination with explicit assumptions about post-2050 policy, while other models (USREP, FARM, and GCAM) are recursive-dynamic, i.e. decision-making is myopic and solely based on contemporaneous variables. Even in an otherwise identical model, the same policy constraint can produce different savings, consumption, and emissions trajectories depending on whether or not consumer expectations about future states of the economy are taken into account.

A key observation is that either of the regulatory policy measures directed towards the transportation and electricity sector, or a combination of both, yield substantially smaller emissions reductions over the 2010–2050 period compared to a 50 percent cap-and-trade policy. More specifically, the CAFE policy results in the smallest emissions reductions of all policies (or combinations thereof) considered. This reflects the fact that demand for private transportation services is relatively inelastic and that advanced low-carbon technologies in the private transportation sector

Figure 3: Cumulative 2012–2050 covered CO_2 emissions—(Optimistic CCS/Nuclear)

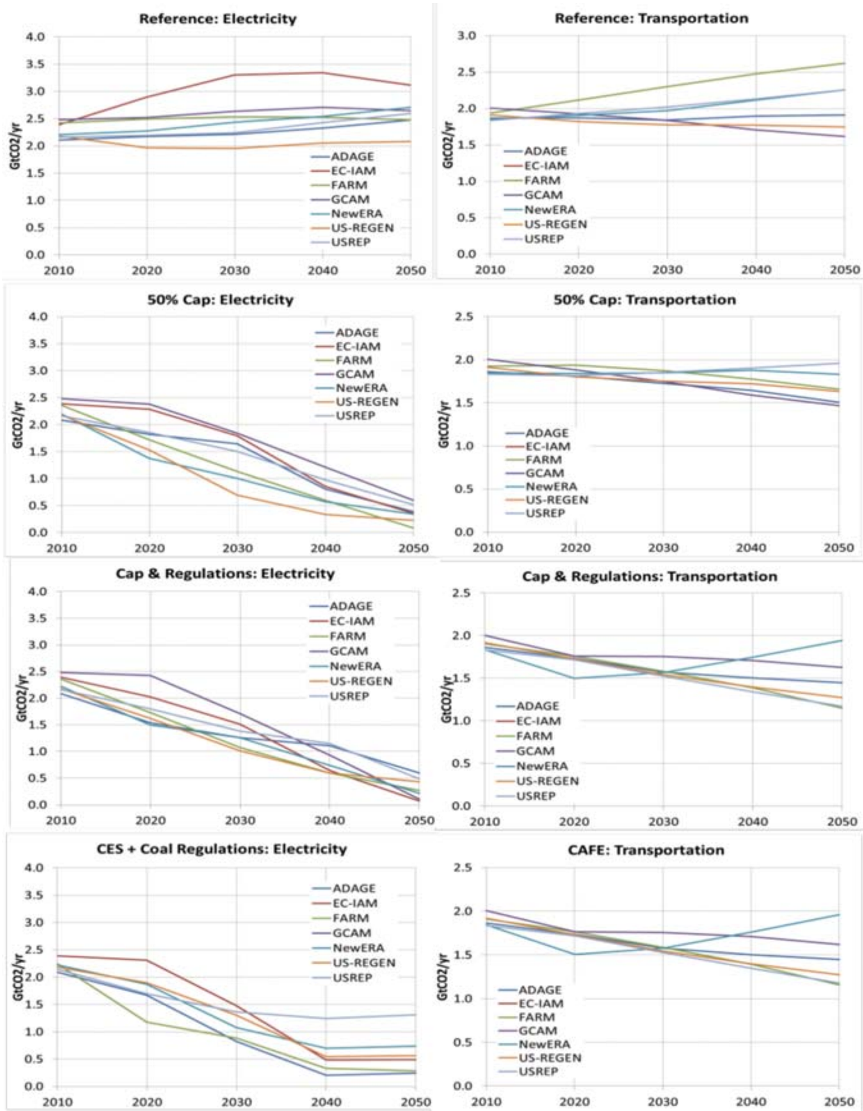


are still costly. Among the policies focused on the electricity sector, CES policy (as specified here) is more effective in reducing CO2 emissions as compared to the RPS policy. Emissions reductions under the combined regulatory policies in the electricity and transportation sector come close but are somewhat lower than the total reductions achieved by a 50 percent cap-and-trade policy. Although the models differ in terms of the absolute level of projected emissions reductions, the preceding observations—as they relate to relative reductions across scenarios—are borne out consistently by each model.

Comparing the variation across models for a given scenario, it is noted that the spread in emissions outcomes is in general slightly larger for the scenarios involving regulatory polices as compared to the reference scenario or the cap-and-trade cases. This variation—reflecting to a large extent the different representation and assumptions of technology and abatement costs—should thus be viewed as providing a range of plausible outcomes that take into account the different modeling inputs and choices embedded in each simulation model.

Figure 3 compares cumulative covered CO_2 emissions from 2012–2050 across models and scenarios. For each scenario, we also report an average across models (black dash); in calculating the model average we assume that each model receives an equal weight. On average, the CAFE policy reduces cumulative emissions only by 8.3 Gt, while both the RPS and CES policies are more effective, reducing cumulative emissions by 34 and 47 Gt, respectively. A combination of both regulatory policies achieves on average a reduction of 43.7 Gt thus amounting to only about 60 percent of cumulative emissions reductions realized under the 50 percent cap-and-trade policy. Interestingly, the standard deviation of cumulative emissions across models for a given scenario does not vary much across scenarios. This suggests that much of the model differences in terms of CO_2 emissions pathways for each policy case in Figure 2 can be explained by factors—which are described above— that drive differences in the reference case. Put differently, while the models in this study, for a given policy instrument, show some variation with respect to the absolute magnitude of cumulative emissions reductions, differences in model projections become much smaller if initial model conditions, i.e. those describing models in the absence of an explicit climate policy, are taken into account. Figure 4 shows CO_2 emissions for the electricity and the combined transportation sectors in the reference and selected policy scenarios for each model. Several insights emerge from

Figure 4: Electricity and transportation CO_2 emissions—(Optimistic CCS/Nuclear)



this graph. First, regulatory instruments in the electricity sector in the form of a RPS or CES policy lead to larger annual emissions reductions in all periods, and hence larger cumulative reductions, as compared to a CAFE policy, which targeted at the transportation sector.

Second, the electricity sector offers less expensive abatement opportunities and a larger potential for reducing CO_2 emissions than does the transportation sector. This becomes evident when comparing the sectoral emission profiles under each regulatory policy with the 50 percent cap-and-trade case. While a policy that puts an explicit price on carbon incentivizes roughly the same amounts of emissions reductions in the electricity sector as a CES + coal CCS requirement policy, the 50 percent cap-and-trade policy reduces emissions in the transportation sector only very slightly. This is an important characteristic of a cap-and-trade policy, which does not force all sectors to reach specified targets but rather the aggregate emission reductions are achieved at the overall least cost of achieving the aggregate emissions reduction target. This implies that the cost of the last ton of emissions abated in the electricity sector is equal to the cost of the last ton of emissions abated in the transportation sector (i.e., that marginal abatement costs are equal).

Third, the sectoral emissions profiles under each respective non-cap and trade regulatory policy are very similar to the emissions observed under a policy that also includes a carbon cap to the sectoral policies. This suggests that each sectoral regulatory instrument is binding, and that additional emission reductions under a combined policy regime are mostly achieved outside of the electricity and transportation sectors. While virtually no difference in transportation sector emissions are discernible between the CAFE and cap-and-regulations cases, an explicit carbon pricing policy provides an incentive for additional reductions in electricity sector emissions beyond 2040 that would not be realized under a CES + new coal CCS requirements-only policy.

4. ECONOMIC IMPACTS

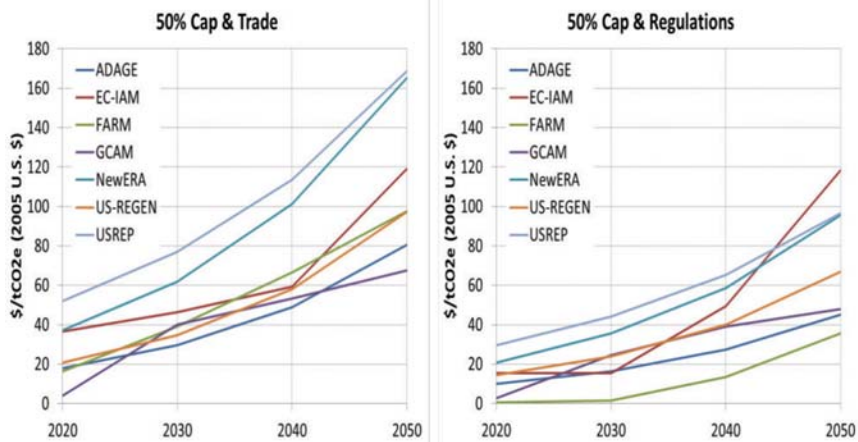
In this overview, we focus on four different metrics for measuring economic impacts: allowance price, consumption loss, GDP loss, and EV. The allowance price is a measure of the marginal cost of abating GHG emissions in a cap-and-trade program, and has been an important cost metric for policy makers in analyses of legislation such as the Waxman Markey bill (e.g. EPA 2009; EIA 2009; Fawcett et al. 2009). The remaining three metrics are measures of a policy's aggregate economic cost. Consumption loss is a measure of the change in consumption of goods and services in the economy. It measures the reduction in the amount of goods and services households can purchase due to increases in energy prices and other costs resulting from GHG abatement. GDP loss combines the change in consumption with the changes in the other components of GDP: investment, government expenditures, and net exports. While policy makers are often interested in GDP loss as a metric of the overall impact on the economy, changes in consumption are sometimes a preferred cost metric because utility (and thus welfare) is a direct function of consumption. The final cost metric considered here is equivalent variation (EV), a measure of household welfare. EV is the difference between reference case household expenditures and the expenditures households would need to be as well off in the GHG reduction case if prices were held constant at reference case levels. For economists, EV is often the preferred cost metric; however, it is sometimes difficult to communicate to policymakers.

It is important to note that this study is a cost-effectiveness analysis with a primary focus of comparing the costs of reaching various GHG emission reduction goals. This study does not quantify the benefits of reducing GHG emissions, so the results cannot be interpreted as a cost-benefit analysis.

4.1 Allowance Prices

Figure 5 depicts allowance prices, expressed in 2005$ per ton of equivalent carbon dioxide ($/t$CO_2$e), for a 50 percent cap-and-trade policy with and without CAFE standards in the transportation sector and RPS + New coal CCS requirements in the electricity sector. For the cap-and-trade policy without sectoral policies, allowance prices range from $3.9/t$CO_2$e for GCAM to $51.9/t$CO_2$e for USREP in 2020, and from $67.3/t$CO_2$e for GCAM to $168.3/t$CO_2$e for USREP in 2050. Several factors lead to differences in allowances prices. First, a major driver of differing cost estimates is technology, or substitution possibilities available in the models. Higher capital costs for nuclear or CCS, or restrictions on the penetration rate of these technologies, would both tend to increase allowance prices. Second, a model with high growth in GHG emissions in the baseline

Figure 5: Allowance prices under cap-and-trade policy with and without sectoral polices—(Optimistic CCS/Nuclear)



after 2012 (for example, USREP) will have to abate more and will thus generate higher allowance prices. Third, the flexibility of the capital stock will influence how quickly old technologies can be phased out and new technologies can be adopted. Finally, models differ with respect to the assumed interest rates used for banking.[5]

The dispersion of allowances prices across models is reduced if regulatory policies are added to the cap-and-trade policy. In 2020, FARM has the lowest (\$0.7/tCO_2e) and USREP the highest allowance price (\$29.7/tCO_2e). In 2050, allowance prices range from \$44.9/tCO_2e for ADAGE to \$118.4/ CO_2e for EC-IAM. Smaller differences in allowance prices across models are largely explained by the fact that allowance prices are significantly lower if sectoral regulatory policies are part of the policy package. Emissions reductions forced by CAFE and RPS + New coal CCS requirements mean that in the presence of an economy-wide cap less abatement has to occur elsewhere, thus reducing the demand for allowances and their equilibrium price.

One important insight of this study is that the allowance price is a poor metric of the societal cost of reducing GHG emissions if regulatory instruments are part of a climate policy package. In such cases, focusing on the carbon price can hide substantial costs and is likely to lead to false policy conclusions. We therefore now turn to other metrics of a policy's aggregate economic cost that are more appropriate under such circumstances.

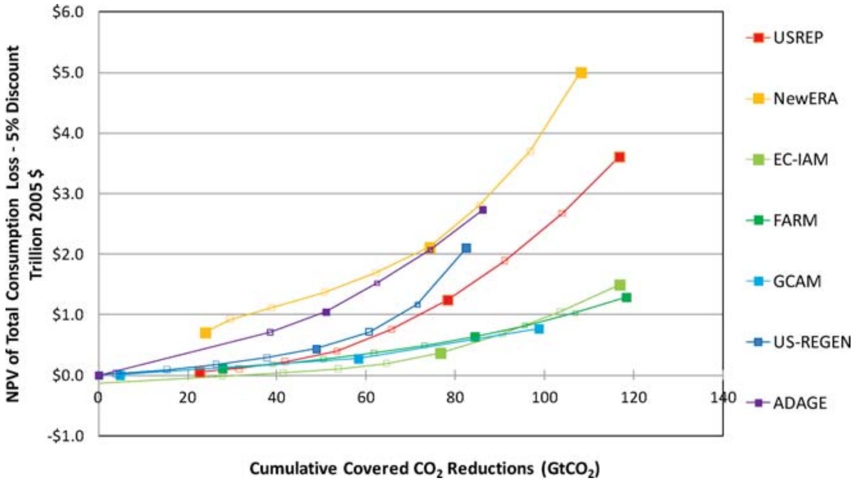
4.2 Efficient Frontier—Cap & Trade

Comparing policy costs across scenarios that reach different levels of GHG emissions can be difficult, and comparing those scenarios across models that require different amounts of abatement to achieve the same GHG levels only compounds the difficulty. When analyzing a single cap-and-trade policy for example, a cost-effectiveness study can compare how policy costs evolve over time across scenarios that vary things other than the cap level. In order to compare cost-effectiveness across models and scenarios, Figure 6 plots the net present value (NPV) of total consumption loss,[6]

5. Most models in this study assume a 5 percent interest rate per year, the USREP model has a value of 4 percent.

6. Consumption loss is chosen as the cost metric for this figure because it is reported by most of the models included in this section. The one exception is GCAM, which only reports the area under the marginal abatement cost curve (MAC), but is still plotted against the other models here for comparison.

Figure 6: Efficient frontiers—consumption loss vs. covered CO_2—(Optimistic CCS/ Nuclear)



discounted at 5 percent per year, on the vertical axis against the 2013 through 2050 and cumulative reductions in covered CO_2 emissions on the horizontal axis. Measuring costs in terms of the NPV of total costs is a cumulative cost measure that allows us to remove the time component associated with when costs are incurred and more readily compare across models and scenarios. Given that climate change is primarily a stock pollutant problem, a non-discounted cumulative measure of emissions is also appropriate and further allows us to ignore or remove the time dimension. Finally, since reference case emissions differ between models, measuring cumulative abatement on the horizontal axis means that the cost-effectiveness can be compared between models based on similar levels of effort.

Figure 6 presents all of the cap-and-trade scenarios, from 0 percent reduction from 2005 levels by 2050 to 80 percent reduction from 2005 levels by 2050, for the “optimistic CCS / nuclear” technology assumptions.[7] Each differently colored line connects points representing successively more stringent cap-and-trade policies in a particular model. The leftmost solid square for each line represents the 0 percent cap-and-trade policy that holds emissions constant at 2005 levels, and the rightmost solid square represents the 80 percent cap-and-trade policy that lowers emissions to 80 percent below 2005 levels by 2050. In the middle of each line is a solid square representing the 50 percent cap-and-trade policy, and the smaller hollow squares in between represent additional cap-and-trade policies incremented by ten percentage points of additional reductions from 2005 levels by 2050. We can think of each of these lines as an efficient frontier for one particular model. For the class of models represented in this figure, the most efficient policies for reducing GHG emissions generally allow for maximal “when”, “where”, and “what” flexibility, i.e. allow banking and borrowing allowances across time, equalize the cost of abatement across all emissions sources, and cover all greenhouse gases.[8] One important caveat is that allowance revenue in these scenarios is

7. For the purposes of this section, the “optimistic RE” scenarios provide similar insights. Section 4.3.5 further explores the differences between the “optimistic CCS / nuclear” scenarios and the “optimistic RE” scenarios.

8. Note that the policies here deviate from maximal “when” flexibility by not allowing borrowing, and deviate from maximal “where” flexibility by not covering CO_2 emissions from land use and land use change. Most of the models here find that the efficient emissions paths bank allowances, and thus the “no banking” constraint is not binding. For the GCAM model, however, the restriction on banking is a binding constraint, so the efficient frontier could be shifted out by relaxing this constraint.

recycled through lump sum transfers to households. If instead, however, allowance revenue generated by the cap-and-trade policy was used to lower other distortionary taxes, the efficient frontier would shift down or to the right.[9]

As an example of how Figure 6 helps to compare cost-effectiveness across models, consider the 50 percent cap-and-trade scenarios in ADAGE and NewERA. If we just compare the NPV of total consumption loss, this scenario is 98 percent more costly in NewERA ($2.1 trillion) than in ADAGE ($1.1 trillion). This comparison gives an incomplete picture of the cost of abatement in these two models, because they have very different assumptions about baseline emissions levels, and the amount of abatement required to meet the 50 percent cap-and-trade target is substantially different: a 51 $GtCO_2e$ reduction in ADAGE compared to a 74 $GtCO_2e$ reduction in NewERA. Figure 6 allows us to see that the level of abatement in the ADAGE 70 percent cap-and-trade scenario is actually equivalent to the level of abatement in the NewERA 50 percent cap-and-trade scenario, and comparing the costs of those two scenarios, they are almost identical. This figure shows that while these two models have very different costs in specific scenarios, costs for any given level of abatement are similar, and the efficient frontiers for these two models look similar.

4.3 Sectoral & Regulatory Approaches Compared to the Efficient Frontier

In this section, we explore how the sectoral and regulatory policies compare to the efficient frontiers presented in Figure 6, and how that comparison is affected by changing cost and emissions metrics. We will also further explore the differences between consumption loss and GDP loss cost metrics by looking at the impacts on different components of GDP. Then we will investigate some of the model differences that are driving some of the specific results seen here.

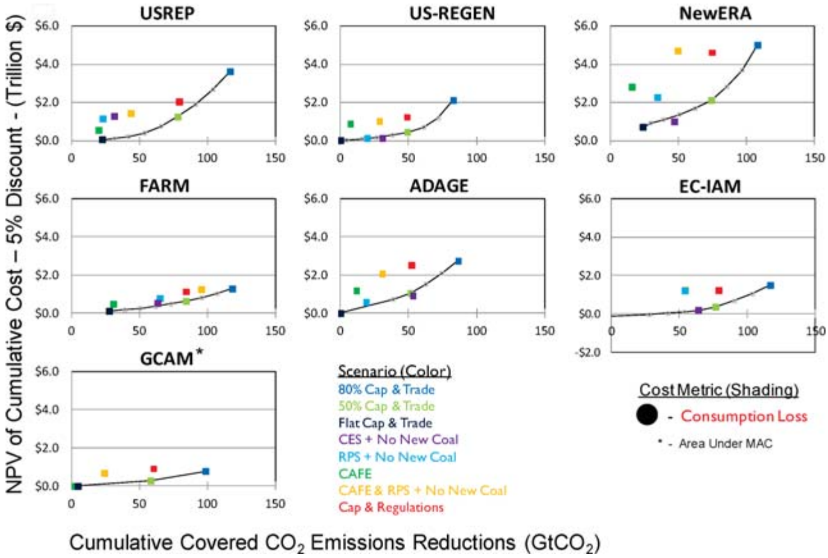
4.3.1 Comparison of Cost Metrics

Figure 7 takes the same efficient frontiers represented by the cap-and-trade scenarios for each model in Figure 6, presents them in separate smaller plots for each model, and overlays the sectoral and regulatory scenarios. For the points off of the cap-and-trade efficient frontier line, the green square represents the transportation policy scenario, the light blue square represents the RPS scenario, the purple square represents the CES scenario, the yellow square represents the combined RPS and transportation policy scenario, and the red square represents the cap-and-regulations scenario, which combines the 50 percent cap-and-trade policy with the CAFE, RPS, and new coal CCS requirements.

The first thing to notice in Figure 7 is that for the most part the sectoral and regulatory policies fall inside (i.e., above) the efficient frontier. In all models the cap-and-regulations scenario generates similar abatement levels to the 50 percent cap-and-trade scenario, differing by at most 4 percent (CGAM and EC-IAM), with higher cumulative consumption loss. However, the difference in consumption loss between these two scenarios differs considerably between models; in USREP, the cap-and-regulations scenario is 62 percent more costly than the 50 percent cap-and-trade sce-

9. In this sense, the label "efficient frontier" may be misleading as there exist policies that would achieve the same cumulative emissions reductions at lower costs than those depicted by the frontiers in **Error! Reference source not found.**. While increased cost-effectiveness may be achieved by recycling the carbon revenue through lowering pre-existing distortionary taxes— for example, through cutting marginal personal income tax rates— it should be clear that such a carbon tax swap involves an explicit choice about fiscal policy. In this study, we abstract from potential efficiency consequences of carbon revenue recycling by assuming that the revenue is returned as a lump-sum transfer to households.

Figure 7: Sectoral & regulatory policies and efficient frontiers—C loss vs. covered CO_2



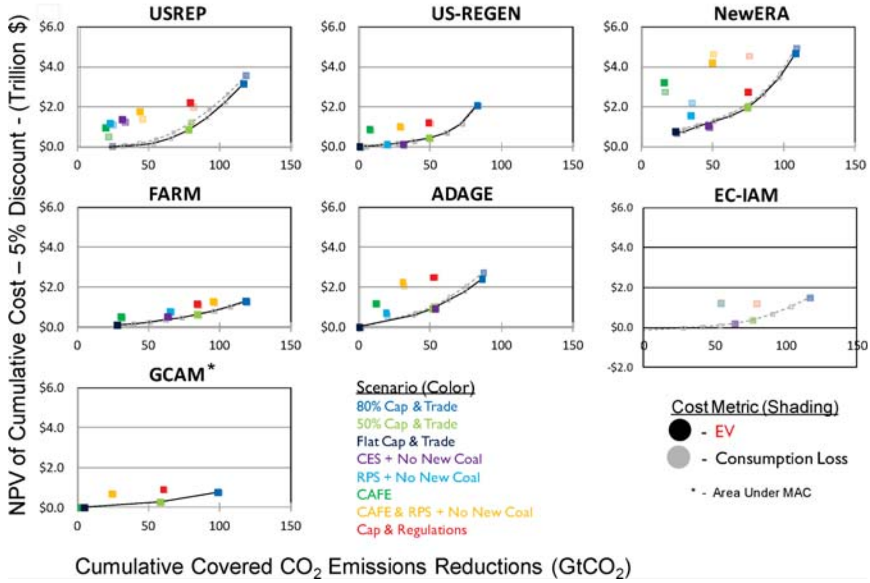
nario, whereas in EC-IAM it is 230 percent more costly. We can also compare the cap-and-regulations scenario (yellow squares in Figure 7) with the combined sectoral policy scenario. All of the models show that the percentage increase in cumulative abatement from adding a 50 percent cap-and-trade policy to the combined CAFE, RPS, and new coal CCS requirement policies is greater than the percentage increase in cumulative costs. The combined regulatory scenario can then be compared to the scenarios representing its constituent policies separately. In three of the models, NewERA, US-REGEN and ADAGE, compared to the RPS scenario, the CAFE scenario generates less abatement with greater consumption loss. For USREP, FARM and EC-IAM, the RPS still generates greater abatement, but at greater cost than the CAFE policy. Finally the CES scenario can be compared to the RPS scenario. This comparison is heavily dependent on the technology assumptions. In the “optimistic CCS / nuclear” scenarios presented in Figure 7, all of the models find greater abatement in the CES scenario. The US-REGEN, NewERA, FARM and EC-IAM models, however, also find lower costs in the CES scenario, while USREP, and ADAGE find higher costs in the CES scenario. Interestingly, US-REGEN, NewERA, and ADAGE all show the CES to lie beyond the efficient frontier, though this effect disappears in ADAGE when considering all covered GHG emissions, and for NewERA the effect is dependent on the technology assumptions used.[10]

Next, we look at how these results change when we use EV as a cost metric instead of consumption loss. The solid points and lines in Figure 8 present the results for all scenarios using EV as the cost metric; and for comparison, Figure 8 also presents all of the results from Figure 7, using consumption loss as the cost metric, as points using faded colors, and a dashed line for the consumption loss of the efficient frontier.

Looking at only the efficient frontiers all of the models show that costs in terms of EV are very similar, but generally slightly less than consumption loss. USREP finds larger percentage

10. This effect is discussed in section 4.3.4.

Figure 8: Sectoral & regulatory policies and efficient frontiers—EV vs. covered CO_2

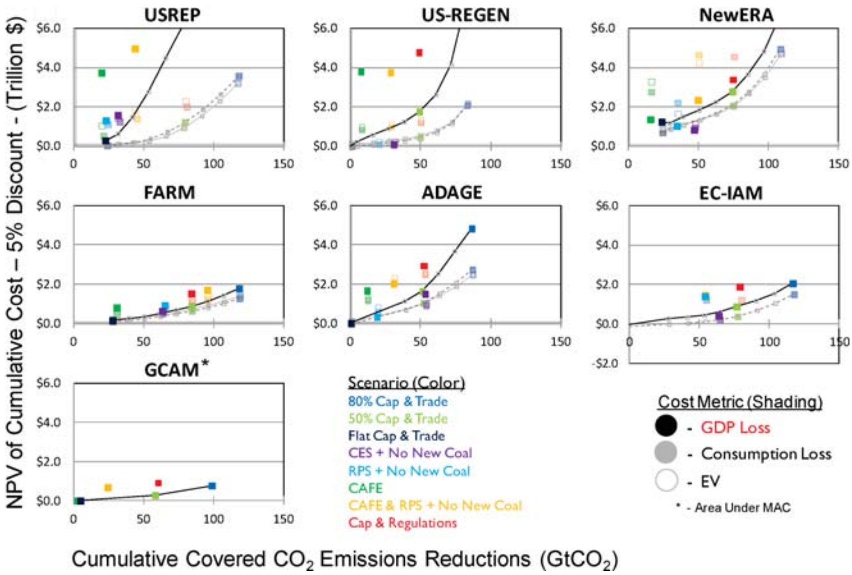


differences in the low-cost, low-abatement cap-and-trade policies (EV costs are 120 percent less than consumption loss in the 0 percent cap-and-trade scenario, though costs are near zero). As the cap-and-trade scenarios, however, become more aggressive and costs rise, the percentage difference falls to 32 percent for the 50 percent cap-and-trade policy and to 13 percent for the 80 percent cap-and-trade policy. NewERA shows a similar pattern; EV is 18 percent less than consumption loss in the 10 percent cap-and-trade scenario, falling to 7 percent less in the 80 percent cap-and-trade scenario. For US-REGEN, EV and consumption loss are almost identical, with EV costs being just 2 percent less than consumption loss in all cap-and-trade scenarios. ADAGE's EV costs are 12 to 17 percent less than consumption loss. FARM EV costs are between 8 percent less and 1 percent greater than consumption loss.

Turning to the sectoral and regulatory policies, for some models the choice of cost metric impacts the relation between these policies and the efficient frontier, while for other models this relationship is largely the same under both EV and consumption loss. The biggest change occurs in the USREP and NewERA models. While the cap-and-trade policies were universally less expensive in EV terms than consumption loss terms in USREP, the sectoral and regulatory policies are all more expensive in EV terms. Furthermore, these policies are not uniformly impacted by the choice of cost metric. The RPS and CES policies are respectively just 3 and 7 percent more expensive in EV terms, but the CAFE policy is 78 percent more expensive. NewERA finds the CAFE and RPS policies to be respectively 15 percent and 6 percent more costly in EV terms compared to consumption loss, while the CES to be 31 percent less costly. The EV of the combined regulatory policies is 11 percent less than consumption loss in NewERA, and the EV of the cap-and-regulations scenario is 40 percent less than consumption loss.

Figure 9 builds upon Figure 8 by adding points that use GDP loss as the cost metric, using solid points and lines; keeping the consumption loss metric in the figure as faded points and dashed lines; and keeping the EV loss metric now using faded outlined points and dotted lines. GDP loss shows the most dramatic differences from the other cost metrics, with the largest differences seen

Figure 9: Sectoral & regulatory policies and efficient frontiers—GDP Loss vs. covered CO_2



in the USREP and US-REGEN models. USREP finds that the cap-and-trade policies in the efficient frontier are between approximately 220 percent and 590 percent more expensive in GDP loss terms than consumption loss terms, with the largest percentage difference in the 30 percent cap-and-trade scenario and the smallest in the 80 percent cap-and-trade scenario. US-REGEN similarly shows the 10 percent cap-and-trade scenario to be approximately 900 percent more expensive in GDP loss terms compared to consumption loss, and the difference falls as the cap-and-trade policies become more aggressive, down to approximately 250 percent in the 80 percent cap-and-trade scenario. In the other models, the difference between GDP and consumption loss is much less pronounced for the cap-and-trade polices. NewERA finds the policies on the efficient frontier are 26 to 73 percent more expensive in GDP loss than consumption loss. The GDP loss metric in FARM is 29 percent costlier than the consumption loss metric in the 0 percent cap-and-trade scenario, rising to 37 percent in the 80 percent cap-and-trade scenario. In ADAGE the 40 percent cap-and-trade scenario is 55 percent more costly using GDP loss as the cost metric than it is using consumption loss, and the difference increases to 76 percent for the 80 percent cap-and-trade scenario. Finally, EC-IAM shows very large percentage differences between GDP loss and consumption loss for the low abatement cap-and-trade scenarios where it finds near zero consumption loss but positive GDP loss, but the difference is much less as the stringency of the policy increases, 140 percent greater costs using GDP loss in the 50 percent cap-and-trade scenario falling to 37 percent greater costs in the 80 percent cap-and-trade scenario.

As we saw comparing EV to consumption loss, the relationship between GDP loss and consumption loss can be very different in the sectoral and regulatory policy scenarios compared to the cap-and-trade scenarios. For USREP, the CAFE scenario is 600 percent more expensive in GDP loss terms than in consumption loss terms, but the RPS and CES scenarios are only 14 and 23 percent more expensive. US-REGEN also sees a huge difference between the CAFE policy and the electricity sector policies in this regard. The CAFE scenario in US-REGEN is approximately 330 percent more expensive whereas the RPS and CES policies have GDP losses that are respectively approximately 150 and 44 percent smaller than consumption losses.[11]

4.3.2 Exploration of Cost Metric Differences

For a given policy, differences between the consumption loss and the EV metric are very small across models. A key conceptual difference between the EV metric as opposed to the consumption loss metric is that it values private utility derived from leisure consumption. A standard way of modeling labor supply in economy-energy general equilibrium models is that households face an labor-leisure trade-off whereby the amount of labor supplied in equilibrium is determined as part of the utility maximizing behavior. As the EV metric is based on the utility function, it does take into account the policy impact on labor supply decisions. A carbon pricing policy raises the price of consumption relative to leisure, and hence households reduce the labor supply substituting towards leisure. The flexibility for consumers to avert some of the price increase by demanding less goods and services and by demanding more leisure time implies smaller economic costs if an EV metric is used instead of a pure consumption-based metric. For all models, the EV metric yields smaller costs of a cap-and-trade policy than the consumption loss metric, thus confirming the above reasoning.

Another potential difference between the EV and consumption loss metric is that in models with forward-looking behavior (e.g., US-REGEN), the discount rate used to calculate the NPV costs in Figure 9 differs from the discount rate implicitly used in the model. Also, note that US-REGEN assumes that labor supply is fixed exogenously and hence there is no difference between that consumption loss and EV that derives from leisure consumption.

Turning to the comparison of GDP with the consumption loss/EV metrics, it is useful to start with some general remarks about the issues related to GDP as a measure of well-being. GDP is the most widely-used measure of economic activity. GDP mainly measures market production, however it has often been treated as if it is a measure of economic well-being. Conflating the two concepts can lead to misleading indications about how well-off people are and misrepresent the impacts of policy choices. Material living standards are more closely associated with measures of real household income, and consumption–production can expand while income decreases or vice versa when account is taken of depreciation, income flows into and out of a country, and differences between the prices of output and the prices of consumer products. When evaluating material well-being, economists therefore prefer to look at income and consumption rather than production.[12]

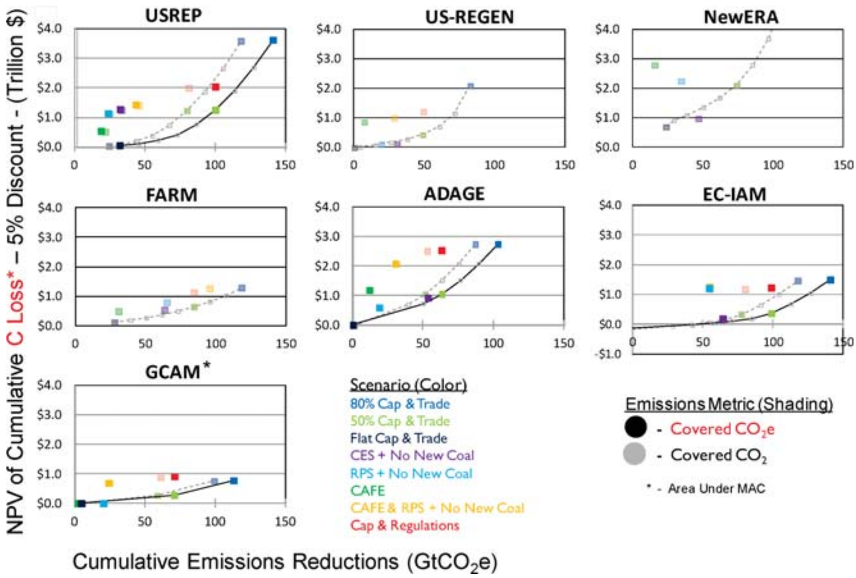
4.3.3 Comparison of Emissions Metrics

Figure 10 shows the NPV of consumption loss versus cumulative emissions reductions for sectoral regulatory and cap-and-trade policies where on the horizontal axis, unlike for previous

11. Appendix A.1 examines the components of GDP to further explores the differences between GDP and consumption loss.

12. The detailed report by the "Stiglitz Commission" (Stiglitz, Sen and Fitoussi, 2009) is the latest attempt to sort through the criticisms of GDP. In addition to material aspects of well-being, income measures would need to be broadened to include non-market activities including, for example, the environment, health, and education. It is worth pointing out that this study provides only an analysis of economic costs of climate policy and does not attempt to incorporate any benefits from averting climate change. Any welfare changes reported in this paper therefore refer to changes in costs.

Figure 10: Sectoral & regulatory policies and efficient frontiers—covered CO_2 vs. covered CO_2e



figures that showed cumulative covered CO_2 emissions, cumulative GHG emissions reductions, including the six Kyoto gases, are shown. Four of the seven models in this study (USREP, ADAGE, EC-IAM, and GCAM) include non-CO_2 GHGs. This figure clearly shows that one important determinant of cost-effectiveness for a carbon pricing policy is the flexibility to choose "what" greenhouse gas to abate, thus ensuring that marginal abatement costs across multiple gases are equalized. For all four models that include non-CO_2 GHGs the efficient frontier is shifted to the right, indicating that a carbon pricing policy that only targets CO_2 foregoes cheap abatement opportunities associated with non-CO_2 GHGs.

Note that for all cap-and-trade scenarios it is assumed that all GHGs, to the extent modeled, are included under the cap, i.e. the modeling teams were not asked to run a cap-and-trade policy just targeted at CO_2. As a result, economic costs are identical, and the efficient frontiers including all GHGs are just right-shifted versions of the ones that show only CO_2 on the horizontal axis. Cumulative GHG emissions reductions for sectoral regulatory policies remain virtually unchanged as these policies are designed to target CO_2 only.

It is important to realize that for relatively low abatement levels the inclusion of non-CO_2 GHGs in a cap-and-trade policy yields bigger percentage increases in cumulative CO_2e emissions reductions compared to more stringent targets (while holding economic costs constant). For more ambitious targets, the efficient frontiers for the two cases tend to move more in parallel, thus implying that the percentage increase in cumulative emissions reductions is decreasing in the stringency of the policy. For designing cost-effective cap-and-trade policy, it is therefore of particular importance to include non-CO_2 GHGs when policy targets with a low to medium stringency are considered.

4.3.4 Further Exploration of Model Differences

Figure 8 shows that for some models (US-REGEN, NewERA, ADAGE) the CES + New coal CCS requirements have smaller welfare impacts (in terms of EV) than an economy-wide cap with a comparable level of overall abatement. One question arising from Figure 8 is why do the costs of the technology mandate lie below the efficient frontier.

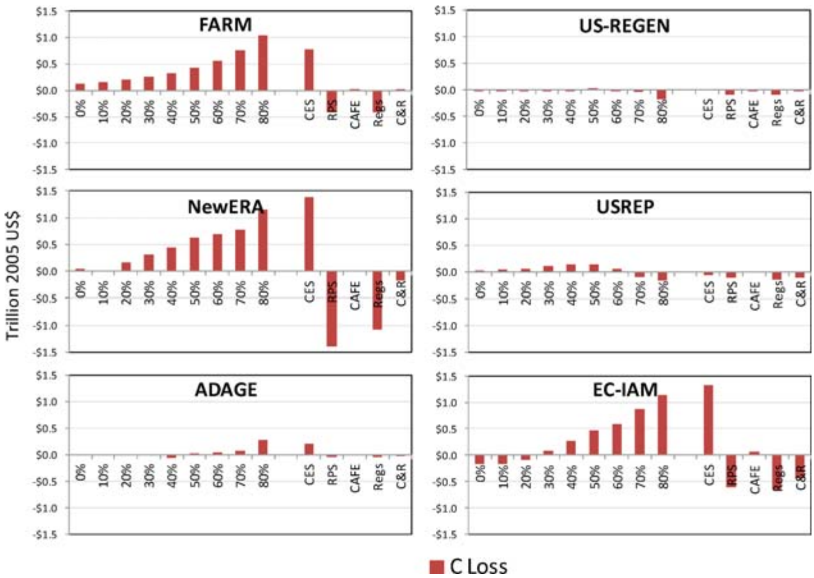
In a first-best world without pre-existing distortionary taxes (for example, income, payroll, and sales taxes), regulatory policies always lead to larger costs of carbon abatement than a carbon tax or permits as the former fail to equalize the marginal cost of abatement across sources and users. The welfare ranking of these policy instruments in a second-best setting, however, is ambiguous. While it has been shown that the presence of pre-existing taxes may significantly raise the cost of carbon pricing policies relative to their costs in a first-best world, the cost increase is even larger for policies that do not use the carbon revenues to finance cuts in distortionary taxes (see, for example, Goulder et al., 1999, and Parry et al., 1999). By driving up the price of carbon-intensive goods relative to leisure, a carbon pricing policy tends to compound the factor-market distortions created by pre-existing taxes, thereby creating a negative welfare impact termed the tax-interaction effect. If the carbon revenue is returned as a lump-sum payment to households, as is the case in the cap-and-trade scenarios in our study, the revenue-recycling effect is zero, implying that the overall impact of pre-existing taxes is to raise costs. In turn, an electricity sector policy that yields a smaller increase in the consumer price of electricity as compared to a carbon-pricing policy may actually be a more efficient way to achieve a comparable level of abatement, given carbon-pricing's vulnerability to distortionary tax interaction. In addition, such a welfare ranking of policies is also facilitated by the fact that the CES policy is roughly equivalent to an electric-only cap plus an output subsidy. Thus, it is allocating abatement efficiently within the electric sector, but it is inefficient in terms of both substitution at the end-use level as well as abatement in non-electric sectors. Moving to an economy-wide cap should correct these remaining inefficiencies and reduce the total welfare impact. However, moving to a cap (i.e., removing the output subsidy for electricity and adding a tax on non-electric fuels) introduces a countervailing inefficiency through the distortionary factor tax interaction.

In models with relatively steep abatement costs in the non-electric sectors and a relatively flat curve in the electric sector, the efficiency gain from the economy-wide coverage in terms of lowering total abatement cost is not very large, and as a result the CES is very close to efficient abatement allocation anyway (but without raising fuel prices much). This situation tends to be more characteristic of models that adopt a bottom-up representation of electricity generation and transmission (US-REGEN, NewERA, and ADAGE). On the other hand, models with a top-down representation of electricity generation and low-cost abatement options in non-electric sectors (USREP, FARM, EC-IAM) estimate that the regulatory policies for the electricity sector are less efficient than an economy-wide cap-and-trade policy. Furthermore, it is important to bear in mind that model results can differ according to how well pre-existing tax distortions are represented.

In summary, the existence of prior distortionary taxes in an economy can potentially eliminate the cost advantage of market-based instruments like carbon permits or a carbon tax over a Clean Energy Standard in the electricity sector. In particular, the likelihood of such an outcome may be increased if the carbon revenue that is generated through an explicit carbon pricing policy is not used to fund cuts in (marginal) distortionary taxes.

The presence of distortionary taxes, however, does not necessarily eliminate the cost advantage of any sectoral regulatory policies as can be seen by comparing the policy costs for the transportation sector policy with the efficient frontier. All models consistently estimate that a transportation sector policy is hugely inefficient compared to an economy-wide cap-and-trade policy with a comparable level of emissions reductions. There are two reasons for this. First, the abatement cost curve in the transportation sector is very steep compared to other sectors, largely because

Figure 11: Difference in Difference: NPV of Cumulative Consumption Loss—Optimistic RE Scenarios less Optimistic CCS / Nuclear Scenarios



transportation demand is relatively inelastic and low-carbon technologies for the private transportation sector are still very costly. Second, a policy focused only on the transportation sector forgoes cheap abatement opportunities in the electricity sector, mainly associated with coal-fired power plants, and in non-electric sectors. In all models, both of these effects seem to dominate the negative tax interaction effect.

Model differences in terms of the efficiency costs of a transportation sector policy (relative to the efficient frontier) reflect different assumptions about future fuel economy improvements and market penetration rates of advanced low- or zero-carbon vehicles.

4.3.5 Comparing "Optimistic CCS / Nuclear" and "Optimistic Renewable Energy" Scenarios

The previous sections have all focused on the "optimistic CCS / nuclear" scenarios instead of the optimistic RE scenarios, and for the most part the insights that have been drawn from these scenarios are robust across both sets of technology assumptions. In this section we investigate some of the differences between the two sets of technology assumptions. Figure 11 compares the NPV of cumulative costs in the optimistic RE scenarios to the costs in the "optimistic CCS / nuclear" scenarios, using consumption loss as the cumulative cost metrics Each bar represents the NPV of cumulative consumption loss in a optimistic RE scenario, relative to the optimistic RE baseline, less the NPV of cumulative consumption loss in a "optimistic CCS / nuclear" scenario, relative to the "optimistic CCS / nuclear" baseline. Positive bars represent the additional cost of meeting the policy goals of a scenario in the optimistic RE scenario relative to the costs of meeting those goals in the corresponding "optimistic CCS / nuclear" scenario.

Three of the models (NewERA, EC-IAM and FARM) show a similar pattern across the cap-and-trade scenarios of the optimistic RE scenarios becoming relatively more expensive than the "optimistic CCS / nuclear" scenarios as the required abatement increases, with the 80 percent cap-and-trade scenario being $1.0 trillion (FARM) to $1.1 trillion (NewERA and EC-IAM) more expensive under the optimistic RE assumptions. The other three models (ADAGE, US-REGEN and USREP) find much smaller cost differences between the two technology assumptions in the cap-and-trade scenarios. The CES and the RPS policies for the electricity sector have some of the largest cost differences across technology assumptions. The RPS requires penetration of renewable technologies and gives no credit to nuclear or CCS, so unsurprisingly all models find the RPS to be less costly under the optimistic RE technology assumptions. In contrast, the CES treats all zero carbon generation technologies equally, and all models, except for USREP, find it to be more expensive under the optimistic RE technology assumptions. For both the CES and the RPS, compared to cap-and-trade policies that achieve similar emissions reductions, the costs of the electricity sector policies are more sensitive to the assumptions about technology.

6. CONCLUSION

The EMF 24 exercise was designed to explore the differences and interactions between an economy-wide cap-and-trade approach to limiting greenhouse gas emissions, and a sectoral and regulatory approach to climate policy. The seven models in EMF 24 generally find that for similar levels of abatement, a cap-and-trade policy that places a price on all greenhouse gas emissions is more cost effective than sectoral or regulatory approaches that are limited in coverage and therefore more prescriptive in how emissions reductions are to be achieved. Furthermore, when sectoral and regulatory policies are combined with a cap-and-trade policy, the allowance price may be reduced compared to the cap-and-trade policy alone, but the cost- effectiveness is generally decreased as well. This difference between allowance price impacts and cost effectiveness measures points to another insight from this study, namely that the choice of cost metrics matters. For measuring the true welfare impacts of a policy, EV is the metric preferred by economists, but it is not produced by all models and can be difficult to explain to policy makers. For the models that report both, consumption loss impacts are very similar to EV loss. GDP loss on the other hand is dramatically higher than EV or consumption loss in some models, while only slightly higher in others, making it particularly problematic to use GDP loss to compare costs across models. The EMF 24 exercise demonstrates some of the uncertainty in estimating policy costs by presenting the cross model range of cost estimates, and by analyzing all of the policy options under different technology assumptions, some of the within model uncertainty can be seen as well.

This paper just scratches the surface of information contained in the EMF 24 modeling runs. The technology overview paper (Clarke et al., 2013) in this volume further explores the baseline scenarios and the implications of the full set of technology assumptions. In the rest of this volume the individual modeling teams present their detailed exploration of results and insights from each participating model. Finally, all of the model output data from the EMF 24 exercise will be available from the EMF website and can be used to further explore the issues presented here and many more.

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APPENDIX

A.1 Components of GDP

Section 4.3.2 explored the differences between cost metrics. One of the interesting results from Figure 9 is that for some of the models the three cost metrics all provide costs that are of a similar magnitude, while for other models GDP loss is dramatically greater than consumption loss or EV. In order to shed some light on the differences between models, Figure A.1 decomposes GDP

Figure A.1: NPV of Components of Cumulative GDP Loss

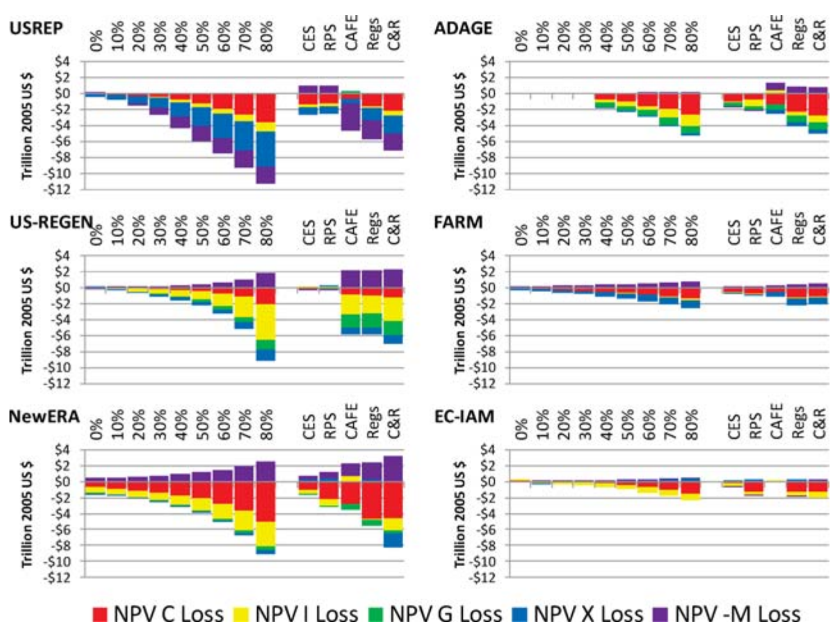
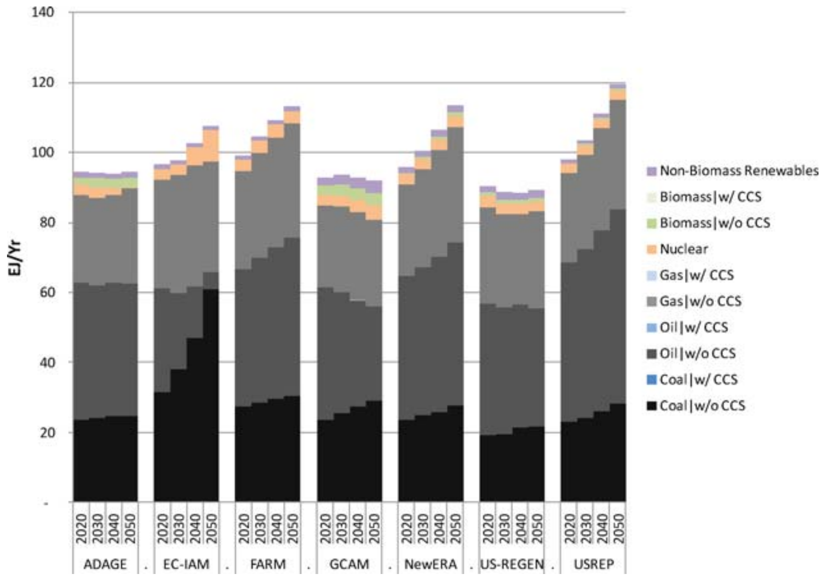


Figure A.2: Primary energy—reference—(Optimistic CCS / Nuclear Scenarios)



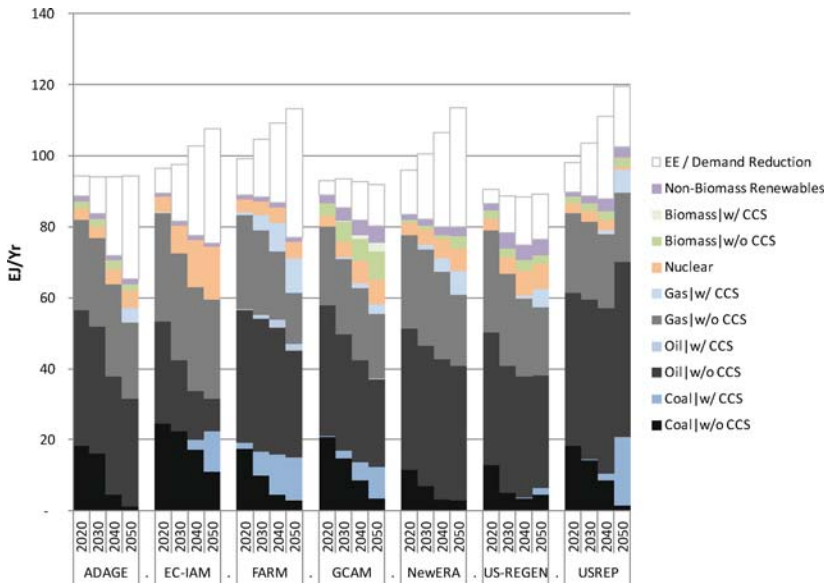
loss into changes in the components of GDP: consumption, investment, government expenditures, exports and imports. Explaining why the components of GDP differ between models is beyond the scope of this paper, but some of the patterns here give more context for the differences between the consumption loss and GDP loss cost metrics. We see for models for which the GDP and the consumption loss or EV metrics show similar magnitude of costs (FARM and EC-IAM) that the consumption loss represents a large fraction of the total GDP loss, whereas for the other models (NewERA, US-REGEN, USREP) the consumption loss represent a relatively smaller fraction.

A.2 Primary Energy

Figure A.2 shows primary energy in the reference scenario across all seven participating models. Growth in primary energy over the next four decades varies across models, with energy consumption in 2050 ranging from a low in US-REGEN of 89.9 EJ/year to a high in NewERA of 119.4 EJ/year . All models show a continued dependence on fossil fuels throughout the time horizon, with EC-IAM substituting gradually coal for oil, while the other models continue to use a balance of coal, gas, and oil. All models show a continued reliance on nuclear power at roughly current levels. Growth in non-biomass renewables in the reference scenario is very modest across all models with a high in GCAM slightly more than doubling from 1.7 EJ/year in 2010 to 3.5 EJ/year in 2050. Overall, the share of non-biomass renewables in total primary energy supply remains small with a high in GCAM of about 3.8 percent in 2050.

Figure A.3 shows the primary energy results for the 50 percent cap-and-trade scenario. Under this scenario, all seven models show substantial reductions in primary energy from the reference scenario, ranging in 2050 from 12.7 percent in GCAM to 31.8 percent in FARM of reference energy. These reductions in energy capture both efficiency improvements and reductions in energy services. The degree to which a model exhibits a reduction in energy use depends on its

Figure A.3: Primary energy—50% Cap & Trade—(Optimistic CCS / Nuclear Scenarios)



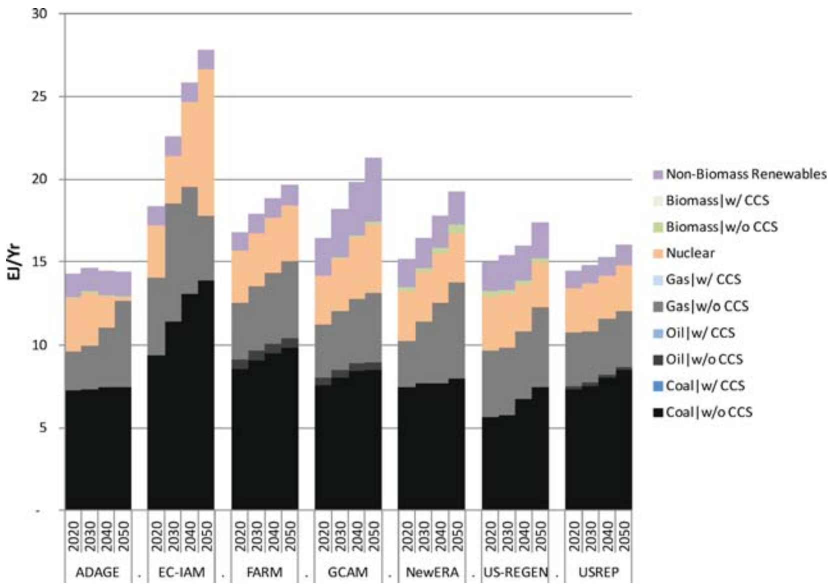
technology availability and consumer response in terms of willingness to reduce energy-consuming activities.

Besides changes in the level of total primary energy consumption, a climate policy also impacts on the energy supply mix. One avenue of reducing emissions associated with fossil fuels is to use CO_2 capture and storage. All seven models include such technologies, but the degree to which it is used varies widely. In NewERA and US-REGEN it does not enter at all; in USREP and GCAM it only enters in the final periods, while FARM projects some substantial deployment beginning in 2030. The role of nuclear in future energy systems under a climate policy varies considerably, ranging in 2050 from a high of about 20 percent in ADAGE and NewERA, to intermediate values of 9 percent in US-REGEN, to a low of less than 1 percent in USREP . Other low-carbon sources (fossil fuels with CCS, bioenergy, and non-biomass renewables) account for between 13.8 percent (NewERA) and 28.1 percent (USREP) of total primary energy supply in 2050 in the 50 percent cap-and-trade scenario. In contrast, these technologies accounted for between 1.5 percent (USREP) and 7.2 percent (GCAM) of total primary energy supply in 2050 in the reference scenario.

A.3 Electricity Generation

Figure A.4 shows electricity generation in the reference scenario. All seven models show an increase in electricity generation from approximately 15.0 EJ/year in 2010 (with a low of 13.7 EJ/year in ADAGE) to between 14.2 EJ/year (ADAGE) to 28.2 (EC-IAM) in 2050. In addition to differences in the estimates of total electricity, there is some variation in projected generation mixes across models. All models show roughly constant levels of generation from coal, with the exception of EC-IAM which estimates a doubling of generation from coal between 2010 and 2050. In general, growth in total electricity is achieved through a combination of increases in generation from gas, nuclear and non-biomass renewables. Between 2010 and 2050, increases in generation from gas range from a low of 10 percent in USREP to a high of 129 percent in NewERA. The share of

Figure A.4: Electricity generation—Reference—(Optimistic CCS / Nuclear Scenarios)



generation from gas in 2050 ranges from a low of 19.4 in GCAM to a high of 49.1 in EC-IAM. For most models, generation from nuclear power increases only slightly, with the extreme cases being ADAGE where nuclear is almost completely phased-out by 2050 and EC-IAM where the share of generation from nuclear is 31.3 percent in 2050. In the absence of a climate policy, growth rates in non-biomass renewables between 2010 and 2050 varies widely. While most models estimates very modest growth over this period, with a constant level of generation from renewables in ADAGE and only slight increases in USREP and NewERA, other models (US-REGEN and GCAM) estimate growth rates between 62.3 and 125.1 percent. The share of generation from renewables in 2050 ranges from a low of 6.7 percent in FARM to a high of 18.1 percent in GCAM.

Figure A.5 shows electricity generation in the 50 percent cap-and-trade scenario. Under a carbon policy, all models show a significant shift toward low-carbon technologies. By 2050, between 51.2 percent (ADAGE) and 86.0 percent (US-REGEN) of all electricity generation is from low-carbon technologies (including nuclear); compared to about 30 percent of total primary energy from low-carbon sources. This is consistent with the result that reduction in emissions the electricity sector is greater than the reduction in economy-wide emissions. While all models shift to low-carbon technologies, different models rely more heavily on different technologies. The general patterns that emerges in one where by 2050 coal without CCS virtually disappears from the generation mixes and where electricity is largely generated from nuclear and non-biomass renewables, together with some remaining gas (without CCS). The technology assumptions underlying this scenario (Optimistic CCS/Nuclear) entail an optimistic stand on prospects for nuclear power assuming that new plants can be built as long as they are economical; the share of generation from nuclear power in 2050 ranges from a low of 7.9 percent in USREP to as high as 62.4 percent in EC-IAM. In USREP, generation from coal with CCS crowds out nuclear power. Model estimates about increases of generation from non-biomass renewables vary widely, ranging between 2010 and 2050 from a low of 1.3 percent in ADAGE to a high 232.2 percent in US-REGEN. The share of generation from non-biomass renewables in 2050 ranges from 9.4 percent in FARM to 25.5 in US-REGEN.

Figure A.5: Electricity generation—50% Cap & Trade—(Optimistic CCS / Nuclear Scenarios)

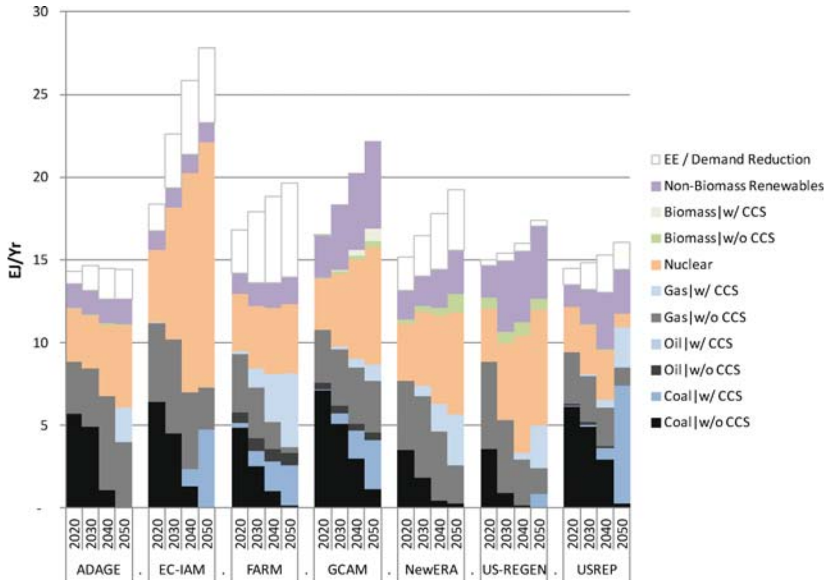


Figure A.6: Electricity generation—50% Cap & Trade + CAFE & RPS + No New Coal (Optimistic CCS / Nuclear Scenarios)

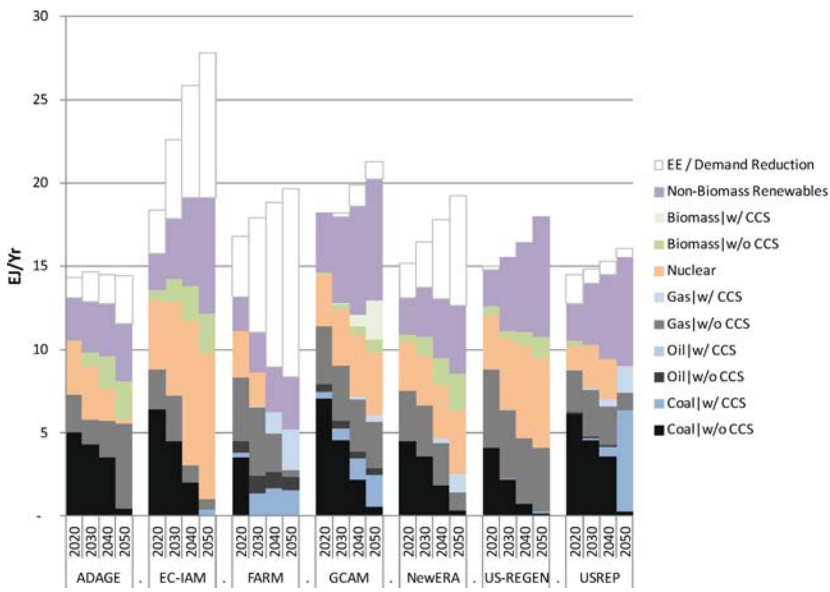


Figure A.6 shows electricity generation for the cap-and-regulations scenario. Imposing a RPS and new coal CCS requirements in the electricity sector leads to different generation mixes as compared to a carbon pricing-only policy as in the 50 percent cap-and-trade scenario. While substantial variations across models exist, the general pattern that emerges is one where there is less dependence on nuclear power, larger levels of deployment of non-biomass renewables, and smaller reductions in coal-based electricity. The RPS instrument directly incentivizes generation from renewables while nuclear power is not credited under such a scheme. In most models, the de-carbonization of the electricity sector in the case of a pure carbon pricing policy, together with optimistic assumptions about the prospects for nuclear power (Optimistic CCS/Nuclear), is achieved by depending on higher levels of nuclear power in the future and some modest growth in non-biomass renewables. For all seven models considered here, this seems to suggests that in the absence of an explicit policy targeted toward incentivizing renewables, such as a RPS, the availability of low-cost generation from renewables that can compete with nuclear power and coal with CCS is limited. While a RPS forces more non-biomass renewables into the generation mix despite of these cost disadvantages, its failure to differentiate non-renewable energy sources/technologies (nuclear, gas, and coal) according to their carbon content is an important impediment for obtaining cost-effectiveness. This also explains why in almost all models generation from coal and gas is still a significant share of total generation in 2050, whereas nuclear plays a relatively modest role.

Figure A.7 highlights the differences in the generation mix under the 50 percent cap-and-trade scenario and the scenario that combines the 50 percent cap-and-trade policy with CAFE standards, RPS, and new coal CCS requirements. Positive numbers represent increased generation under the combined cap-and-regulations scenario compared to the 50 percent cap-and-trade scenario, and negative numbers are decreases in generation. All models show that under the "optimistic nuclear/CCS" technology assumptions biomass and non-biomass renewables generation increases, and nuclear and fossil CCS generation decreases. Given the technology assumptions, the imposition of an RPS on top of the cap-and-trade policy forces the models away from their preferred generation mix.

Figure A.7: Electricity generation—Difference between—50% Cap & Trade Scenario and the Combined Cap-and-Regulations Scenario. (Optimistic CCS / Nuclear Scenarios)

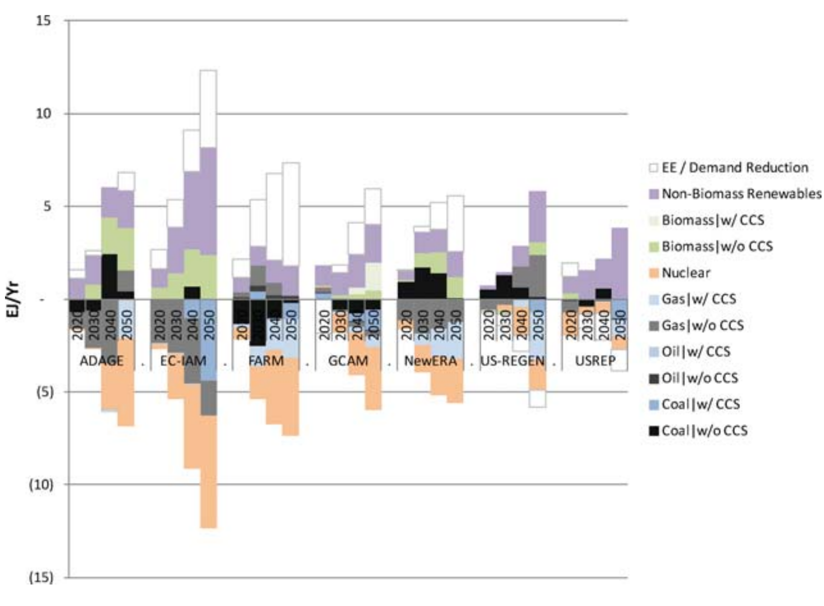
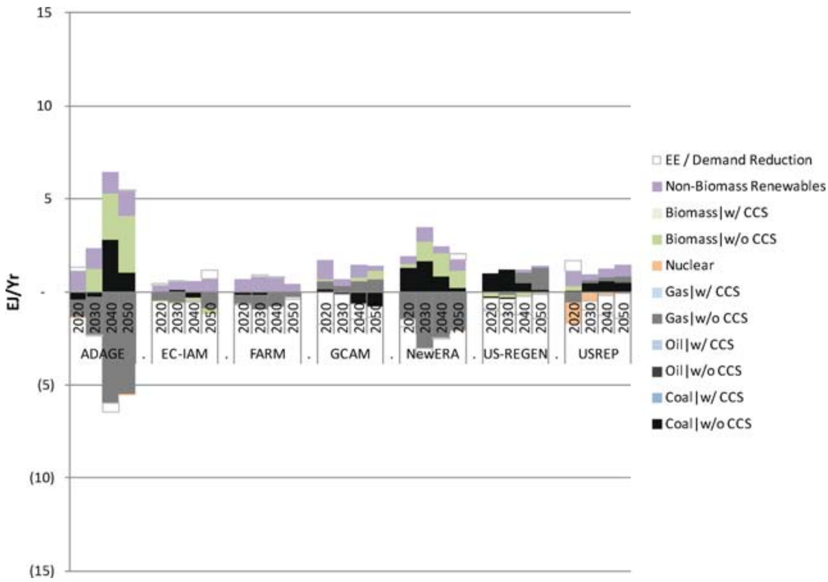


Figure A.8: Electricity generation—Difference between—50% Cap & Trade Scenario and the Combined Cap-and-Regulations Scenario. (Optimistic Renewables)



In contrast, Figure A.8 shows the same comparison under the optimistic RE technology assumptions. Here the models find that the addition of an RPS policy has a much smaller impact on the generation mix. This reinforces the findings shown in figure 11, that all models found the RPS policy and the combined cap-and-regulations policy to be less costly under the optimistic RE technology assumptions.

Interaction Effects of Market-Based and Command-and-Control Policies

Sugandha D. Tuladhar, Sebastian Mankowski*, and Paul Bernstein**

ABSTRACT

Scientific evidence indicates that greenhouse gases emissions related to human activity are a significant contributor to global climate change. This paper investigates the impact of policy prescriptions and technologies for reducing U.S. greenhouse gas emissions. The analysis uses NERA's $N_{ew}ERA$ integrated model, which combines a top-down general equilibrium macro model of the U.S. economy with a detailed bottom-up model of the North American electricity sector. It examines the cost of cutting emissions by 0% to 80% of 2005 levels by 2050 under several scenarios, which consider different assumptions about policy choices ranging from purely market-based policy such as a cap-and-trade program to purely command-and-control policies and technology involving availability and efficacy of nuclear, Carbon Capture and Storage, renewables, and end-use efficiency technology. Our analysis shows a distinct efficiency advantage for market-based mechanisms and interaction of command-and-control mandates with market-based policies increase market distortions leading to higher welfare loss. We show that under such a mixed policy regime, carbon price is an unsuitable indicator of economic costs.

Keywords: Climate change policy, Market-based, Command-and-control, CGE models, Top-down bottom-up models, Low carbon fuel standards, Clean energy standards, Fuel economy standards.

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I. INTRODUCTION

Scientific evidence continues to indicate that anthropogenic emissions of greenhouse gases are a significant contributor to global climate change (IPCC, 2007). Mitigating the impact humans have on the global environment will require significant reductions in GHG emissions. Many scientists believe global GHG would need to decline over the next 40 years by at least 50% from today's levels to prevent global average temperatures increasing by more than 2°C. Achieving this level of reductions will be quite challenging.

The landscape for U.S. carbon policy has evolved significantly over the past several years. As recently as 2009, there were multiple legislative proposals moving through Congress aimed at establishing a national cap-and-trade system for reducing carbon emissions throughout the economy. However, in the wake of the financial crisis and shifting political sentiments, these market-based economic instruments have more or less been scrapped and replaced with proposals for command-and-control regulatory mandate frameworks. These federal frameworks have primarily been pro-

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posed at the sector level, in the cases of a national renewable energy standard (RES), a clean energy standard (CES), a national renewable fuels standard (RFS) for transportation fuels, or a national fuel economy standard (CAFE), or even at a unit level. At the same time, several states and regions are developing and implementing their own versions of carbon legislation, such as the sectoral cap-and-trade Regional Greenhouse Gas Initiative (RGGI) program and the combination mandate and cap-and-trade system in California as a result of AB 32. Policy design is moving away from singular and comprehensive policies to multiple and narrowly-focused policy regimes. This variety of specific and potentially overlapping regulatory regimes creates a complex policy landscape with many potential unforeseen risks and unintended impacts.

This paper investigates two important approaches to reduce GHG emissions in the U.S.: policy prescriptions and introduction of new technologies. The choice of policy is crucial to the availability of capital to develop new technologies and achieving GHG reductions in the most cost-effective manner. Technological breakthroughs and advances in energy efficient technologies are required if the world is to curtail emissions by a meaningful amount while maintaining economic growth. This paper addresses these two aspects by constructing a set of scenarios that varies largely over two dimensions: (1) assumptions about emissions reduction policies and (2) assumptions about technology.

To understand the implications of policy choice, we run scenarios that range from being purely market based such as a cap-and-trade program to policies that are completely command-and-control such as a policy that employs vehicle fuel efficiency standards, emission intensity standards for transportation fuels, and an emissions intensity standard for electric generation. This paper also considers hybrid policies that have both a cap-and-trade program and some command-and-control measures.

Much of the work in this paper builds on a body of work that began in 2007 with an analysis of California's AB 32 policy.[1] The analysis in this paper uses a similar modeling framework to that of Tuladhar et al. (2009) who showed that a national Low Carbon Fuel Standard (LCFS) when combined with a national cap-and-trade program increases overall costs to the economy. Tuladhar et al. (2012) used the N$_{ew}$ERA model to analyze economic efficiency tradeoffs and energy price effects associate with a clean energy standard with a carbon tax policy. Karplus et al. (2012),[2] using a computable general equilibrium model, showed that cost of meeting a greenhouse gas emissions constraint increases when a fuel economy standard is combined with a cap-and-trade policy. Rausch et al. (2012)[3] examined the efficiency and distributional impacts of combining clean and renewable energy standards. They show that command-and-control polices entail significant efficiency costs when compared to a carbon tax or a cap-and-trade program. Clean energy standard policy and renewable energy standard could two and four times than a market-based policy. Morris et al. (2010)[4] analyzed the effects of combining a renewable portfolio standard with a cap-and-trade

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system for the U.S. using a computable general equilibrium model. This study found that the introduction of RPS increased the welfare cost by 25% over the life of the policy relative to a cap-and-trade system only. Our paper contributes to the current literature in three aspects. One, we bring in multi-sector command-and-control policies within a modeling framework that links a "bottom-up" with a "top-down" economic model. Unlike previous analyses, this approach allows us to look at possible efficiency costs associated with cross sectoral distortions. Second, we show the implication of a combined policy on the price of carbon, which is largely omitted from the literate discussion. Third, we further validate the findings of the other analyses that there are efficiency costs associated with combing command-and-control policies with market-based policies.

To compare the cost-effectiveness of the different policies we map out the economically efficient frontier and plot the cost-effectiveness of the command-and-control policies and hybrid policies relative to this frontier. The farther that a policy is away from this frontier, the more inefficient it is.

In considering the effect of technology on the feasibility of achieving needed emission reductions, this paper considers three discreet and diverse sets of scenarios that vary by technological assumptions.

- Nuclear and Carbon Capture and Storage (CCS) will advance as will the efficiency of end-use technology, but large amounts of renewables will be slow to develop;
- Renewables will be prevalent, but no new nuclear and CCS will be allowed. As in the first set, efficiency of end-use technology is assumed to advance at a pace faster than in recent history; and
- Nuclear and CCS will be abundant, but the efficiency of end-use will advance slowly.

To understand the importance of end-use energy efficiency and technology, we compare the cost of cutting emissions by 0% to 80% of 2005 levels by 2050. The model results suggest the maximum emission reductions each technology bundle offers. These runs help inform one about the realistic level of reductions that could be achieved by 2050.

To achieve significant emission reductions, an economy must, in addition to having significant technological advances in supply side resources, improve its end-use energy efficiency. To understand the importance of energy efficiency, we compare the 50% reduction scenarios under two polar assumptions about the evolution of end-use energy efficiency.

In addition, resulting permit prices for the series of scenarios that assume different emission targets for 2050 trace out a marginal abatement cost curve. Viewing this curve suggests what level of emission reductions might be politically feasible and at what point there are diminishing points of return or some other technological breakthrough not modeled in this analysis would be needed.

The remainder of this report is organized as follows. Section 0 describes NERA's modeling system and the scope used for this analysis. Section 0 lays out the scenarios that we analyzed. Then we highlight the key results of the analysis in Section 0. We conclude in Section I.E with insights about policy design and technology assumptions.

II. N$_{EW}$ERA MODEL STRUCTURE AND SCOPE

To conduct this study, we used NERA's N$_{ew}$ERA integrated model, which consists of a top-down, general equilibrium Macro model of the U.S. economy, and a detailed bottom-up model of the North American electricity sector.

The N_{ew}ERA model is used to project impacts of command and control regulations and market-based policies on the economy as a whole and at a sectoral level. Different types of policies could impact a sector in a variety of ways. If a policy leads to an increase in the cost of a factor of production then the policy would have a direct effect of raising the cost of production. A policy that mandates a sector to invest in new capital expenditure would lead to an increase in its production cost through higher cost of capital. Cost of production of a sector (e.g., the natural gas sector) would increase if there are constraints in harvesting the resource. These constraints could arise due environmental concerns or technical barriers, which could have impacts on the entire economy. To account for such effects, one needs to use a model that captures the effects as they ripple through all sectors of the economy and the associated feedback effects.

The N_{ew}ERA modeling framework takes into account interactions between all parts of the economy and policy consequences as transmitted throughout the economy as sectors respond to policies. The model's flexibility allows it to incorporate different natural gas supply curves and evaluate impacts on the economy in a consistent framework.

A. U.S. General Equilibrium Model (Macro Model)

The Macro model is a forward-looking dynamic computable general equilibrium model of the U.S. It simulates all economic interactions in the U.S. economy, including those among industries, households, and the government. Industries and households maximize profits and utility assuming perfect foresight. The theoretical construct behind the model is based on the circular flow of goods, services, and payments in the economy (every economic transaction has a buyer and a seller whereby goods/services go from a seller to a buyer and payment goes from the buyer to the seller). The model includes a representative household, which characterizes the behavior of an average consumer, and seven industrial sectors, which represent the production sectors of the economy. In the model, government collects initial labor and capital tax revenues and returns them back to the consumers on a lump-sum basis.

Households provide labor and capital to businesses, taxes to the government, and savings to financial markets, while also consuming goods and services and receiving government subsidies. Industries produce goods and services, pay taxes to the government, and use labor and capital. Industries are both consumers and producers of capital for investment in the rest of the economy. Within the circular flow, equilibrium is found whereby demand for goods and services is equal to their supply, and investments are optimized for the long term. Thus, supply equals demand in all markets.

The model finds equilibrium by assuming perfect foresight and ensuring goods and services markets balances, production meets the zero profit condition, consumers maintain income balance conditions, there is no change in monetary policy, and there is full employment within the U.S. economy.

The N_{ew}ERA model is based on a unique set of databases constructed by combining economic data from the IMPLAN 2008 (MIG Inc. 2010) database and energy data from Energy Information Administration (EIA's) Annual Energy Outlook 2011 (U.S. EIA 2012). The IMPLAN 2008 database provides Social Accounting Matrices for all states for the year 2008. These matrices have inter-industry goods and services transaction data; we merge the economic data with energy supply, demand, and prices for 2008 from EIA. In addition, we include tax rates in the dataset from NBER's TAXSIM model (Feenberg et al.1993). By merging economic data from IMPLAN, energy data from EIA, and tax rates from NBER, we build a balanced energy-economy dataset.

Macro-economic growth (GDP), energy supply, energy demand, and energy price forecasts come from EIA's AEO 2011. These forecasts are used to define the baseline for this analysis. Labor productivity, labor growth, and population forecasts from the Census Bureau are used to forecast labor endowments along the baseline and ultimately employment by industry. All of these variables (*e.g.*, economic growth rate, energy supply and demand, etc.) are free to change in the scenarios.

The macroeconomic model allows for full interaction among all parts of the economy, but the aggregate representation of the economy leads to one production function (rather than multiple functions) to represent many alternative technologies for each sector that is modeled. We cover this deficiency by modeling the electric sector in detail (described in the next section), enabling us to model environmental regulations that impact the electric sector and ultimately the manufacturing sector through higher electricity prices.

B. North American Electricity Model (Ele Model)

The bottom-up electricity sector model simulates the electricity markets in the U.S. and parts of Canada. The model includes more than 17,000 electric generating units and capacity planning, and dispatch decisions are represented simultaneously. The model dispatches electricity to load duration curves. A long-term solution typically includes ten or more years out through 2050 (each year is not evaluated, but rather representative years).[5] The model determines investments to undertake and unit dispatch by solving a dynamic, non-linear program with an objective function that minimizes the present value of total incremental system costs, while complying with all constraints, such as demand, peak demand, emissions limits and transmission limits, and other environmental and electric specific policy mandates.

The integrated nature of the N_{ew}ERA model enables it to provide interaction of the natural gas demand responses between the electric sector and the rest of the economy. In addition, the framework allowed us to compute impacts on the electricity price consistent with a realistic electric system representation; while being able to compute macro- economic impacts.

We solve the bottom-up and the top-down models iteratively using a block decomposition method (Bohringer et al. 2009) using the MPSGE modeling framework (Rutherford 1999).[6] The top-down macroeconomic model solves for equilibrium prices, while the bottom-up model solves for equilibrium quantities. The solution process is iterated until prices and quantities converge. The integrated approach, illustrated in Figure 1, complements the weaknesses of each of the models and at the same time provides a consistent equilibrium framework.

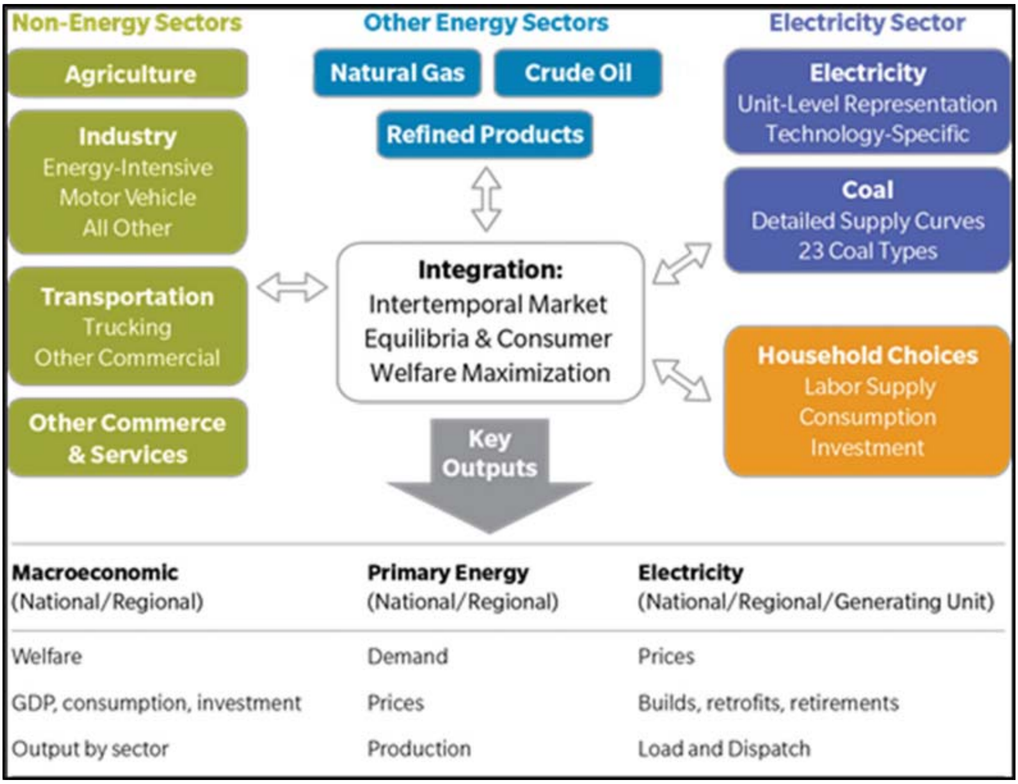
C. Regional Scope of the N_{ew}ERA Model

We model the U.S. economy as a single region. The Ele Model consists of 32 U.S. power pools and are carved out based on NERC regions. The power pools are shown in Figure 2. The

5. The time horizon for this study starts in 2010 and goes out till 2050 in 5-year time steps.

6. Others have used similar decomposition method to solve large integrated models to overcome dimensionality issues. Tuladhar et al. 2009 used similar method to analyze macroeconomic impacts of U.S. climate change policies for three different emissions pathways using a top-down bottom-up integrated model. Lanz et al. (2011) looked at structural alternative for ex-ante policy modeling using an integrated model of a bottom-up electricity sector and a general equilibrium model. Harrison et al. (2012) and Tuladhar et al. (2012a) (2012b) used the N_{ew}ERA modeling system similar to the one used for this paper to evaluate macroeconomic impact of command-and-control policies.

Figure 1: N$_{ew}$ERA Modeling Framework



power pools in the model are different in many dimensions and hence provide interesting impact incidence at the regional level.

D. Sectoral Scope of the N$_{ew}$ERA Model

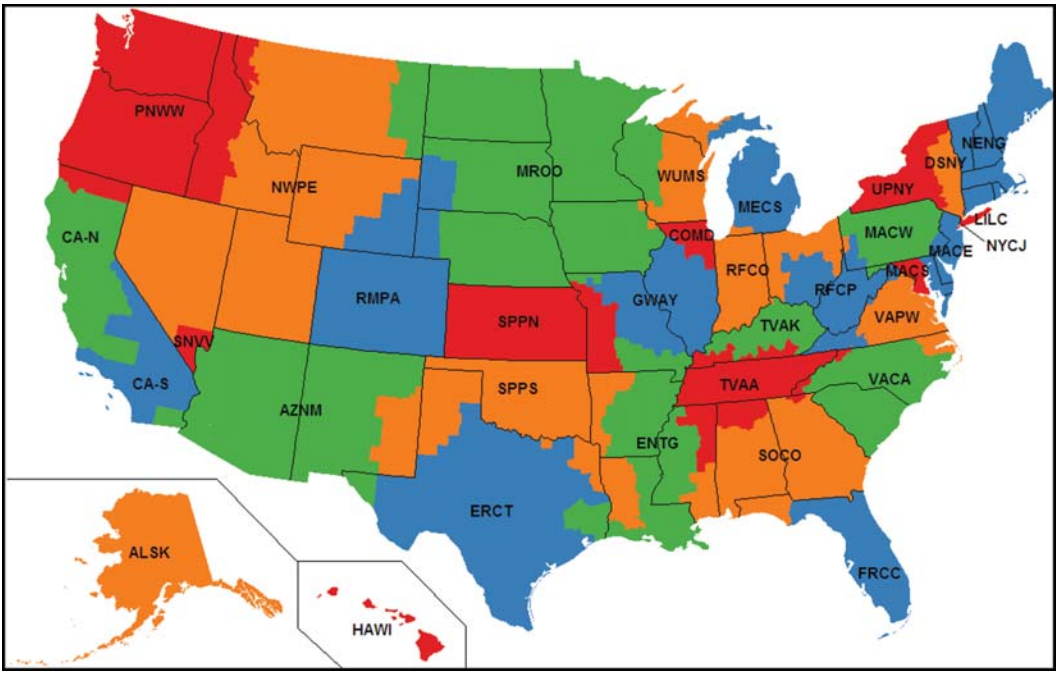
The N$_{ew}$ERA model includes a standard set of 12 economic sectors: five energy (coal, natural gas, crude oil, electricity, and refined petroleum products) and seven non-energy sectors (services, manufacturing, energy-intensive sectors, agriculture, commercial transportation excluding trucking, trucking, and motor vehicles). These sectors are aggregated up from the 440 IMPLAN sectors. We break out energy-intensive sector as a separate sector since it would have varying degrees of impacts as a result of change in natural gas price.

III. DESCRIPTION OF SCENARIOS ANALYZED

To assess the economic impacts of reducing and efficacy of policy measures to reduce greenhouse gas emissions, we designed scenarios considering three different assumption dimensions:

- Policy design;
- Electric sector technology; and
- End-use efficiency.

Figure 2: Power Pool Regions in the N$_{ew}$ERA Model



To concentrate the analysis on the above items, we fixed a number of key assumptions across all the model runs. These assumptions are centered on international issues of policy design of a cap-and-trade program.

The scenarios in the EMF-24 study are built from combinations of policy design, electric sector technology assumptions, and end-use energy efficiency assumptions (Clarke et al. 2013 and Fawcett et al. 2013). This paper considers two broad baskets of technology assumptions, and then runs a series of policy scenarios under each of the two technology baskets.

The following sections describe the technology and policy/goal assumptions in more detail. To assess the impacts of each scenario, each policy scenario includes an assumption about end-use efficiency, electric sector technology, and greenhouse gas abatement policy.

A. Reference Scenarios

A reference, or no policy scenario, is run for each combination of electricity sector technology and end-use efficiency that we considered. The reference scenario assumes no climate policy. It does, however, include the energy or related policies that might influence GHG emissions that have been enacted by the end of 2010. The reference scenarios are built around AEO 2011 assumptions. All reference scenarios assume the same energy prices, non-electric carbon emission forecasts, and economic growth rate as in the AEO 2011 Reference Case.

Because of the differences in assumptions about N$_{ew}$ERA's electric generation technology and end-use energy efficiency, the Reference scenarios, however, do vary from the AEO's electric sector outlook in electricity demand, energy use in the electricity sector, and hence total economy greenhouse gas emissions.

B. Policy Options for Scenarios

This analysis considers several different command-and-control policies, carbon abatement caps, and combinations of command-and-control and cap-and-trade.

1. Command-and-Control Policies

This section discusses the four command-and-control regulations that were considered in some of the scenarios: Renewable portfolio standard (RPS), clean energy standard (CES), coal generation requirements, and fuel economy standards for vehicles.

- **Renewable Portfolio Standard (RPS)**: The RPS applies only to the electricity sector. The RPS policy requires a particular share of electric generation to come from renewable sources. In this analysis, renewable energy includes all hydroelectric power and bio-energy as well as solar and wind. The RPS is defined as 20% by 2020, 30% by 2030, 40% by 2040, and 50% by 2050. Banking and borrowing of RPS (or renewable energy) credits are not allowed.
- **Clean Electricity Standard (CES)**: This policy is similar to the RPS, but also includes nuclear power, fossil electricity with carbon capture and storage (credited at 90%), and natural gas (credited at 50%) in the portfolio. Both new and incremental generation from all eligible generation types may receive credit. Because many additional sources are allowed to receive credit, the targets are defined as linearly increasing from reference levels in the first year of the policy (the first model time-step after 2012) to 50% by 2020, 60% by 2025, 70% by 2030, 80% by 2035, 90% by 2040, and constant thereafter (note that the current share of clean energy in the U.S., as defined here, is 42.5%). All other characteristics are identical to the RPS. In particular, banking and borrowing of CES credits are not allowed.
- **Requirements for new Coal (Reg)**: This policy requires that all new coal power plants capture and store 90% + of their CO2 emissions.
- **Fuel Efficiency Standards (TRN)**: The transportation policy covers emissions from personal transportation only that is defined in the model as light-duty vehicles less than 8500 pounds. To control emissions from light-duty personal vehicles, this policy includes a corporate average fuel economy (CAFE) standard for light-duty vehicles. The CAFE specifies a linear increase in fuel economy of new vehicles, starting in 2015 from 25 miles per gallon (MPG) to 45 MPG by 2035 and beyond.

2. Cap-and-Trade Options

We varied the carbon caps. The caps are described by their 2050 target, which ranges from no reduction from 2005 levels to a deep reduction of 80% below 2005 levels by 2050. We consider caps at each 10% increments between 0% and 80%.

The cap-and trade program represents the assumption of a national policy that allows for cumulative greenhouse gas emissions from 2012 through 2050 associated with a linear reduction from 2012 levels to the desired long range target of anywhere between 0% and 80% below 2005 levels in 2050. The cumulative emissions are based on the period starting from, and including, 2013 and through 2050. The cap covers CO_2 emissions from all sectors of the economy.[7]

C. Generation Technology Options

This analysis considers two different baskets of generation technology options, where the basket includes assumptions about the four generation technology dimensions: (1) CCS, (2) nuclear fission, (3) wind and solar power, and (4) bioenergy. The baskets differ in their assumptions about whether nuclear and CCS or renewables become the low carbon technologies for the electricity sector. The baskets also differ in their assumption about the cost of energy efficiency:

- **Basket 1:** High availability of CCS and nuclear and low availability of bioenergy, wind, and solar.
- **Basket 2:** Low availability of CCS and nuclear and high availability of bioenergy, wind, and solar.

The remainder of this section describes the elements in the basket and the meaning of high and low for each element.

1. Carbon Capture and Storage (Nuclear/CCS):

- **CCS Unavailable (Low):** No implementation of carbon capture and storage technology.
- **CCS Available (High):** CCS is available. The cost and performance characteristics resemble those in the AEO 2011.

2. Nuclear Energy (Nuclear/CCS):

- **Nuclear Phase Out (Low):** Nuclear power is phased out after 2010. The phase out is defined as no construction of new nuclear power plants beyond those already under construction or planned (excluding proposed plants).[8] This reflects the concept of the “off” case being triggered by public skepticism about nuclear technology. In addition, we assume no lifetime extensions beyond 60 years as representing an environment that generally discourages the development and deployment of nuclear energy.
- **Nuclear Available (High):** New nuclear energy is fully available. The cost and performance characteristics resemble those assumed for the AEO 2011.

3. Renewable Energy (Renewable): Wind and Solar Energy:

- **Low-Tech (Low):** Low-tech techno-economic assumptions for solar and wind energy assume slow evolutionary technology development for both wind and solar energy.
- **Hi-Tech (High):** High-tech techno-economic capacity assumptions for solar and wind energy technologies are about twice as great as those of the Low-Tech case.

7. Historic U.S. GHG emissions are taken from the “2011 U.S. Greenhouse Gas Inventory Report” on-line at (http://epa.gov/climatechange/emissions/usinventoryreport.html).

8. We allow 1.2 GW of new nuclear capacity to come online in 2014.

Figure 3: Capacity Limits for Each Basket of Technology Assumptions (GW)

			2010	2011-2020	2021-2030	2031-2040	2041-2050
Basket 1	High Nuclear/CCS	CCS	0	4.0	44.0	82.0	100.0
		Nuclear	0	17.2	40.0	40.0	40.0
	Low Renewable	Bioenergy	0	6.5	15.3	17.8	21.8
		Solar/Wind	0	59.3	103.5	113.5	123.5
Basket 2	Low Nuclear/CCS	CCS	0	0	0	0	0
		Nuclear	0	1.2	0	0	0
	High Renewable	Bioenergy	0	13.0	30.5	35.5	43.5
		Solar/Wind	0	106.5	207.0	227.0	247.0

4. Renewable Energy (Renewable): Bioenergy:

- **Low-Tech (Low):** The low-tech scenario represents a scenario where bioenergy is assumed to be difficult to procure because of limited supplies of bio crops. We assumed that biocrops could support just over 20 GW of biomass based capacity by 2050.
- **Hi-Tech (High):** The hi-tech scenario assumes technological breakthroughs in the procurement of bioenergy. Therefore, supply and efficacy are much higher than in the Low-Tech case. We assume enough biocrops will exist to support 40 GW of electricity capacity.

Figure 3 summarizes our assumed capacity limits for each technology type.

D. End Use Technology (EUT):

This analysis also makes two different assumptions about end-use technology: Low EUT and High EUT.

- **Low EUT:** The low-technology case represents evolutionary assumptions about the availability, cost, and performance of technologies that would reduce energy consumption at the end use or enhance opportunities for fuel switching.
- **High EUT:** The high technology case represents plausibly optimistic assumptions about the availability, cost, and performance of technologies that would reduce energy consumption at the end use or enhance opportunities for fuel switching. In particular, electricity demand in the Low EUT baseline assumes that electricity consumption is assumed to increase linearly to about 20% more by 2050 compared to the High EUT baseline (see Figure 4).

Figure 4 shows the annual energy demands modeled under each EUT assumption.

Figure 4: Annual Energy Demand with High and Low (EUT) Assumptions (TWh)

	2020	2030	2040	2050
High EUT	4.20	4.56	4.92	5.33
Low EUT	4.41	5.01	5.66	6.40

E. List of scenarios

We combined the different assumptions about policy design, technology, and end-use energy to develop 32 scenarios.[9] All policies employ the same assumptions about international issues and cap-and-trade program specifications. The table below (Figure 5) shows all of the assumptions for each of the 32 scenarios examined.

To summarize, we considered three final combinations of generation technology assumption baskets and EUT assumptions for our modeled scenarios.

- **HHL:** This is a combination of the first basket of generation technology assumptions (High Nuclear and CCS availability, Low Renewable availability) and the High EUT assumption.
- **HLH:** This is a combination of the second basket of generation technology assumptions (Low Nuclear and CCS availability, High Renewable availability) and the High EUT assumption.
- **LHL:** This is a combination of the first basket of generation technology assumptions (High Nuclear and CCS availability, Low Renewable availability) and the Low EUT assumption.

F. International/Additional issues

There are many other assumptions or policy levers that can have a significant effect on the cost-effectiveness of GHG mitigation policies. Some of the key assumptions pertain to assumptions surrounding climate change policies implemented by other countries, availability of offsets, international trade, and availability of bioenergy, banking and borrowing of permits in a cap-and-trade program, and method of recycling permit revenues. To limit the dimensionality and areas in which models could differ, for all the scenarios studied in our analysis, we assumed the following about international policy, trade in bioenergy, offsets, banking and borrowing, and permit revenue.

- **International Policy:**[10] We do not assume anything on the international policy side; therefore, there are no terms of trade feedbacks from what other countries might do if the U.S. were to reduce GHG emissions.

9. The scenario naming convention and the general scope of the scenarios analyzed in this paper is described in detail in Clarke et al. (2013) and Fawcett et al. (2013).

10. In NewERA, the U.S. exports goods to a downward sloping demand curve by good and imports from an upward sloping supply curve by good. If prices in the U.S. increase relative to the rest of the world, then the U.S. will likely import more goods and export less. Therefore, if the U.S. imposes a carbon policy upon itself, there will be some leakage of carbon overseas both in terms of the U.S. increasing its exports of coal, but also in terms of the U.S. importing more goods.

Figure 5: Matrix of the 32 Scenarios of Technology and Policy Dimensions Analyzed in this Study

	Scenario		
Technology	HHL	HLH	LHL
End Use Technology	High	High	Low
CCS	High	Low	High
Nuclear	High	Low	High
Wind & Solar	Low	High	Low
Bioenergy	Low	High	Low
Policy Dimension			
Baseline	US02F	US01F	US21F
Cap &Trade 50%	US04F	US03F	US22F
Electricity (Coal +RPS) +Transport	US06F	US05F	
Electricity (Coal +RPS) +Transport+50%Cap&Trade	US08F	US07F	
Transport	US10F	US09F	
Electricity (Coal +RPS)	US12F	US11F	
Electricity (Coal +CES)	US28F	US27F	
Cap &Trade 0%	US30F	US29F	
Cap &Trade 10%	US32F	US31F	
Cap &Trade 20%	US34F	US33F	
Cap &Trade 30%	US36F	US35F	
Cap &Trade 40%	US38F	US37F	
Cap &Trade 60%	US40F	US39F	
Cap &Trade 70%	US42F	US41F	
Cap &Trade 80%	US26F	US25F	

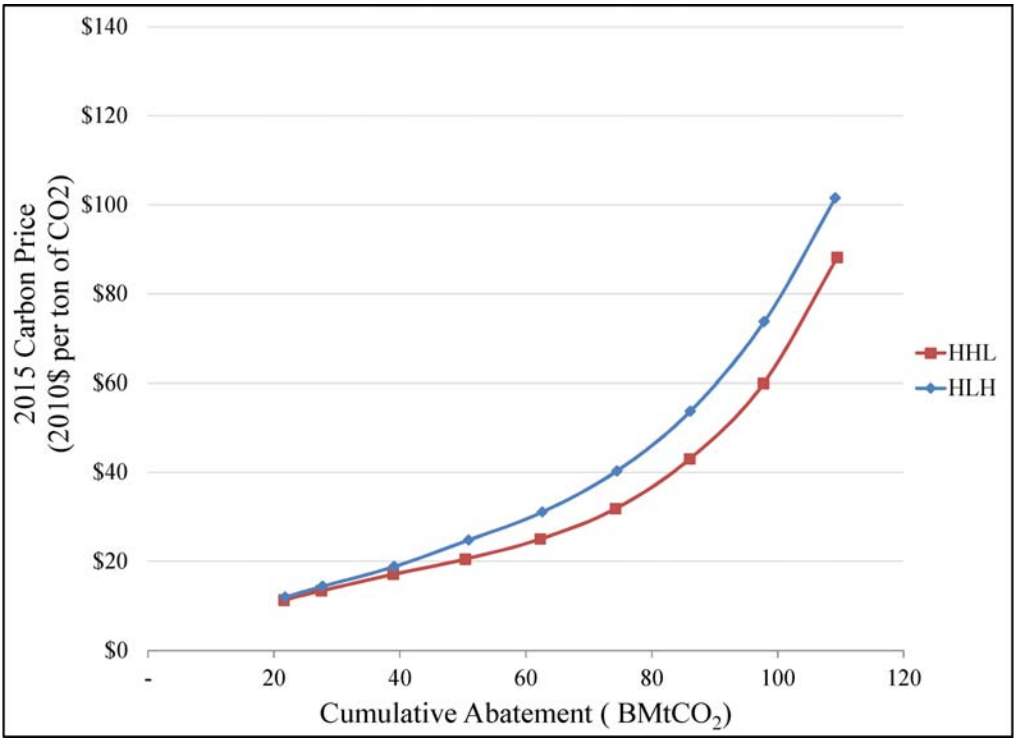
- **International Trade in Bioenergy:** We assume the U.S. produces all its own biofuels and does not import any.
- **Offsets:** No offsets are assumed to exist.
- **Banking and Borrowing:** We allow banking and prohibit borrowing.
- **Permit Revenue:** All permit revenues are assumed to be refunded lump sum to households.

IV. RESULTS

A. Emission Reductions through Market-Based Mechanisms

Our analysis shows a distinct efficiency advantage for market-based mechanisms over command and control regulatory approaches to reducing carbon emissions. To show the efficiency

Figure 6: Price of Carbon in 2015 for Different Levels of Cumulative Abatement (2010$/ tCO_2)



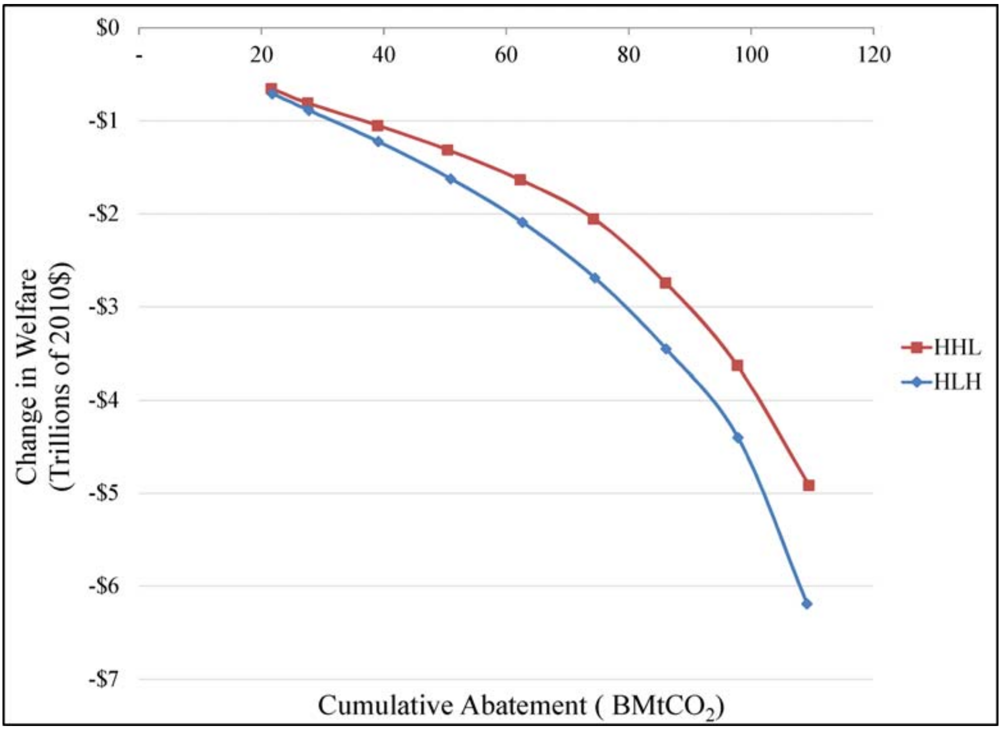
advantage, we first construct an efficient frontier by plotting the locus of abatement levels against welfare loss (or carbon price) for all of the cap-and-trade scenarios.

Figure 6 and Figure 7 depict, respectively, the curves for the marginal cost of carbon abatement and welfare costs[11] for given technology assumptions and given levels of carbon abatement. The primary reason for this efficiency advantage lies in the fact that the market-based mechanism allows for trading of reduction efforts amongst all sectors of the economy. This ability to dynamically allocate responsibility for emissions reductions to where they are least expensive minimizes the marginal abatement costs across the economy. It is important to note that our modeling framework assumes no market failures or market imperfections.

As the market-based solution to carbon abatement is the most cost efficient abatement method, these cost curves represent the efficient frontier of costs for a given set of assumptions about the availability of different technologies. As can be seen, the assumptions on relative availability of nuclear and renewable generation have a notable impact on the cost of the market-based solution to carbon abatement. The scenario with greater availability of nuclear generation and CCS, HHL, has lower costs per ton of emissions reduced than the scenario with greater renewable availability, HLH. The greater availability of newly built nuclear generation capacity relative to most newly built renewable generation capacity (our renewable generation availability assumptions,

11. Welfare costs or changes in welfare are computed as the change in the equivalent variation of welfare (Hicksian compensation).

Figure 7: Change in Welfare for Different Levels of Abatement (Trillions of 2010$)

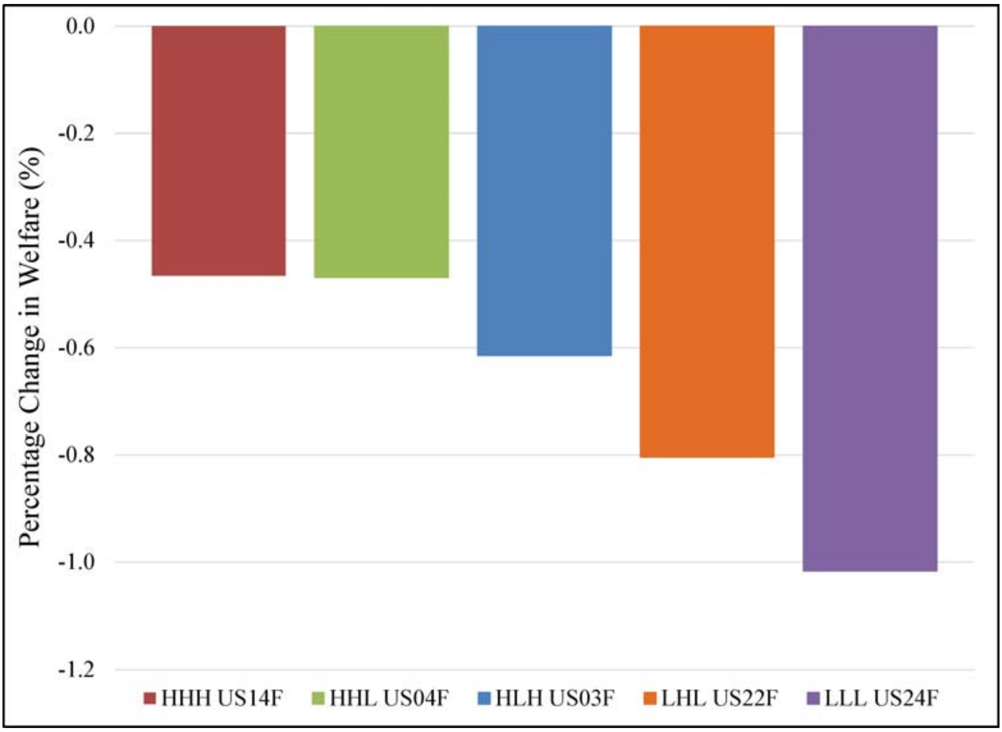


which are approximately half of the level we assume for nuclear generation, lower the capacity factor, or utilization rate, of wind and solar generation are a significant factor in the outcome that the levelized cost of wind and solar generation exceeds that of nuclear and CCS generation)[12] results in less total additional capacity being needed. This reduced need for additional new generating capacity leads to a lower marginal cost of abatement, a lower carbon price, and therefore a smaller loss in welfare.

While the market-based solution to carbon abatement proves to be the most efficient way to reduce carbon emissions in general, as measured by the welfare costs, the figures above indicate the potential importance of technology availability in determining the position of the efficient frontier. We find that in the scenario (not shown in the figures) where end-use technology, nuclear, and renewables are all abundantly available, the change in welfare is the lowest, as would be expected. Interestingly, the reduction of renewables availability in the HHL scenario (comparing US14F to US04F) has minimal impact on welfare cost results. Conversely, reducing availability of nuclear, the HLH US03F scenario relative to the HHL US04F scenario, does have a notable increase in

12. The relative efficiency advantage of nuclear over renewables (HHL and HLH scenarios) is largely dependent upon the underlying availability and cost assumptions. Additionally, limits on the amount of generation capacity of each technology type that can potentially be built annually differ from the HHL to the HLH scenarios. In the HLH scenario we do not allow any new nuclear or CCS generation to be constructed beyond what is already in progress. As a result, due to the much lower availability assumption of renewables relative to nuclear or CCS generation, a great deal more zero-carbon generation capacity must be built in the HLH scenario relative to the HHL scenario and contributes to the greater overall costs.

Figure 8: Percentage Change in Total DPV Welfare from 2010–2050 for Different Technology Availability Assumptions

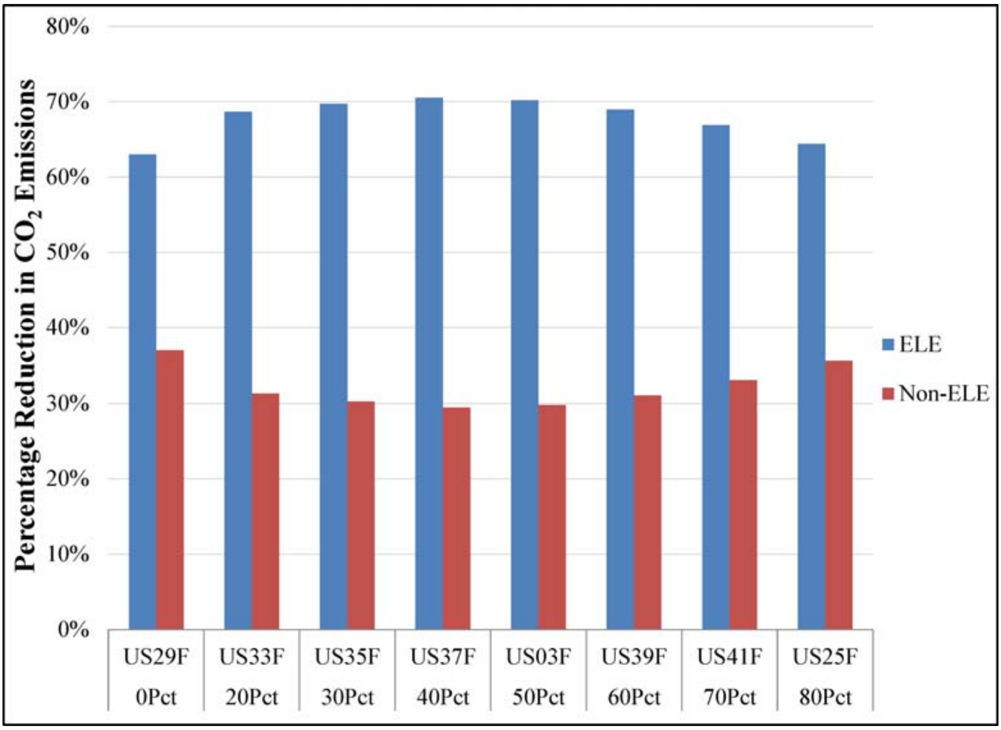


welfare costs. These differences between nuclear and renewable availability apply for the scenarios with low end-use technology availability as well. The welfare changes for these scenarios can be seen in Figure 8.

Figure 9 shows the relative share of emission reductions that occur in the electric sector compared to the non-electric sector for HLH. The shape of the shares of emission reductions shows that at lower reduction target levels the share of the economy's reductions occurring in the electric sector increases up to a point and then, at the 50% target reduction level and beyond, begins to decrease relative to the non-electric sector reductions as the abatement targets become more stringent. This reflects the finding of most models[13] that the least cost emissions abatement opportunities exist in the electric sector and as those least cost opportunities are exhausted the more costly non-electric sector reduction contributions are required. At the lower levels of reduction targets, replacing coal generation with natural gas generation, nuclear generation, and renewable is less costly than non-electric sector abatement alternatives. As the targets become more stringent and the more expensive electric sector abatement options, such as CCS, are required, non-electric sector abatement options become relatively more cost effective, primarily in the transportation sector in the form of more biofuels. This relationship is an effective depiction of the relative costs of abatement in the electric sector versus the non-electric sector and reinforces a fundamental reason as to why

13. Ellerman, Denny A. and Natsuki Tsukada, "CO2 Abatement by Multi-fuel Electric Utilities: An Analysis Based on Japanese Data" Joint Program on the Science and Policy of Global Change, MIT Report No 76, 2001.

Figure 9: Share of Total Cumulative U.S. Reduction in CO_2 Emissions by Electric and Non-Electric Sectors for HLH

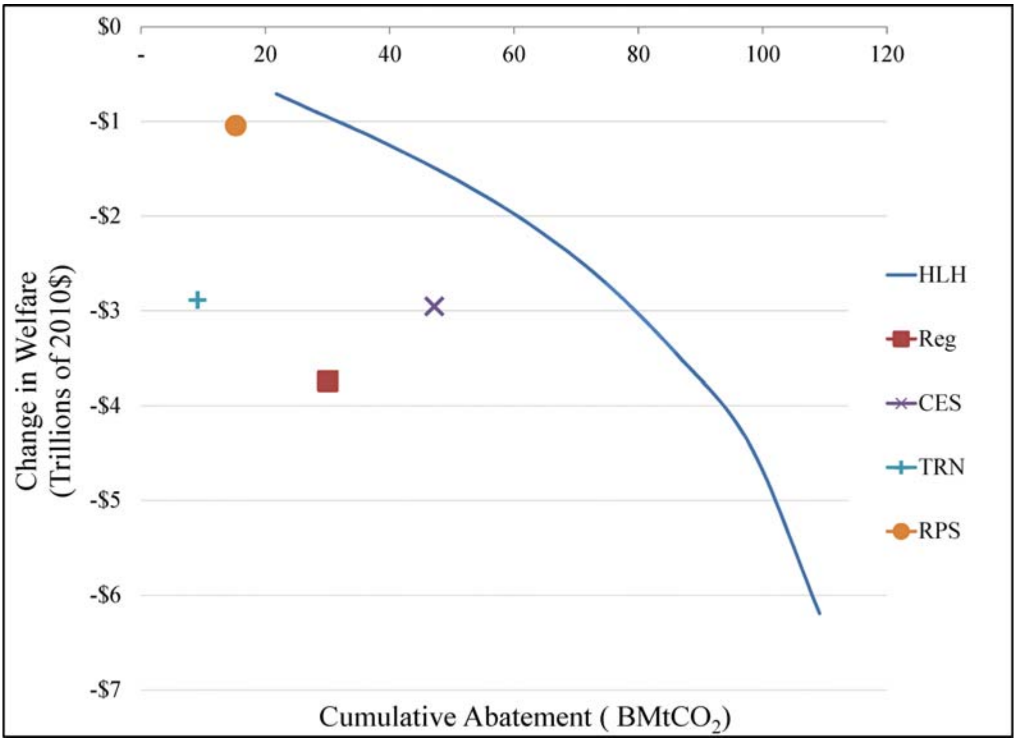


an economy-wide cap-and-trade policy is more cost efficient than command-and-control regulatory mandates as discussed in Section I.B below.

B. Emission Reductions through Mandates and Regulations

Although market-based mechanisms provide the most cost efficient abatement of carbon emissions, there are those who believe markets are inherently inefficient or flawed. This view of market inefficiency tends to point to various economic barriers, such as information asymmetry, principal-agent problems, and monopoly powers, as reasons that regulatory mandates are necessary in order to improve upon perceived market failures. With this in mind, we examined where various regulatory mandates and combinations of mandates fall in relation to the efficient frontier of a market-based mechanism (where we assume no market failures or imperfections). Our results indicate that the cost-effectiveness of all regulatory mandates and combinations of mandates are less than that of the market-based policies with similar levels of emission reductions. Figure 10 illustrates this result. The symbols represent policies consisting solely of regulatory mandates s while the line represents the market-based cap-and-trade policies. All the data points represented by symbols reside to the left of the efficient frontier thus showing the cost of policies with regulatory mandates either achieve less reductions for the same cost or the same level of emission reductions can be achieved at less cost under a market based policy.

Figure 10: Changes in Discounted PV of Welfare from 2010–2050 for Regulatory Mandates Compared to Efficient Frontier (Trillions of 2010$)

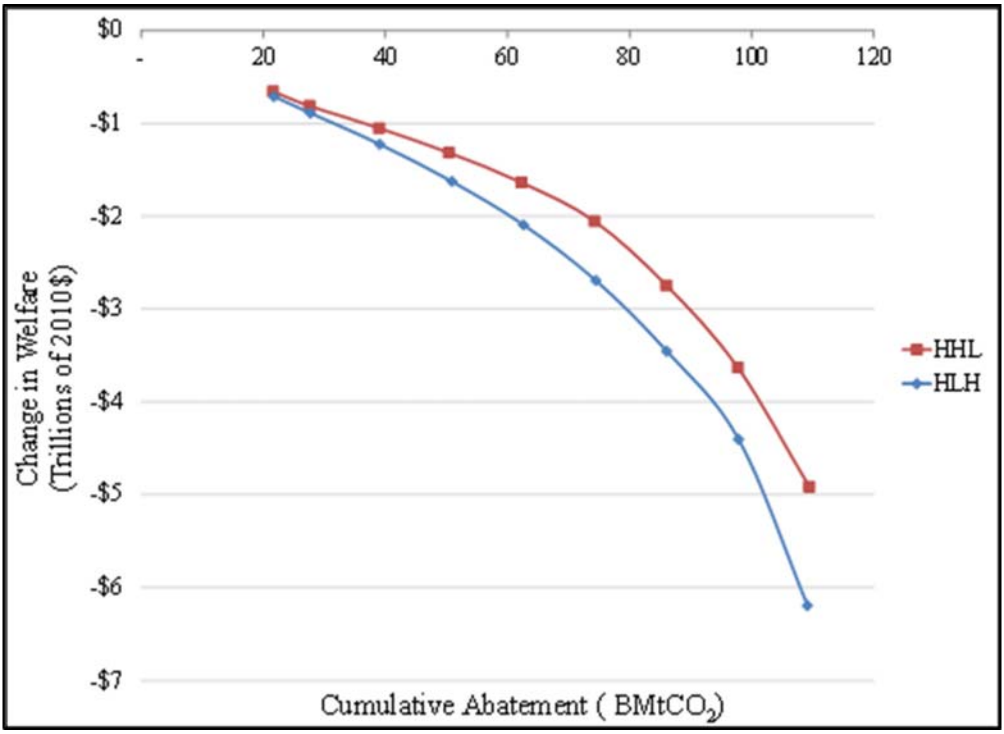


Among the regulatory policies some are better than others. Policies that address emissions from the electricity sector are far more cost-effective than those that only address emissions from the transportation sector.

The TRN policy that imposes CAFE standards obtains about the same emission reductions as the RPS policy but for about three times the cost. Put differently, for the same cost as the TRN policy, regulators could impose a CES policy instead and achieve about four times the emission reductions. These comparisons illustrate that regulatory policies aimed at controlling emissions from the electricity sector are more cost-effective than those aimed at the transportation sector. This result holds because the options for reducing emissions in the electric sector (*e.g.*, switching from coal to gas or fossil fuel to renewables or nuclear) are more cost-effective than mandates to raise emission standards in the transportation sector. These relative differences and the fact that reducing emissions from the electricity sector is the economy's best option keep the RPS policy from being too much more costly than the market-based cap-and-trade program. Given that the TRN scenario appears to be the least cost efficient approach among all the scenarios, the Reg combination also ends up being relatively inefficient from a welfare cost perspective.

The primary difference between the market-based mechanism and the scenario with a CES or RPS is that these policies require abatement from only the electric sector whereas the market-based mechanism is economy-wide and allows for the most cost-effective abatements from each sector to be utilized. In fact, this is the primary issue with all command and control regulatory approaches, regulators are required to implement several different policies rather than one and the

Figure 11: Change in Welfare for Different Levels of Abatement (Trillions of 2010$)



lack of interaction between the policies results in efficiency losses by not necessarily targeting the least cost sources of emissions first.

C. Relationship of Carbon Mitigation[14] and Costs

At a certain level of targeted emission reductions the costs start to increase exponentially relative to the emission reduction benefits. In our modeling we began to see this knee in the marginal cost of abatement curve approximately around the 50% to 60% emission reduction target, or around approximately 85 $BMtCO_2$ of cumulative reductions as seen in Figure 11.

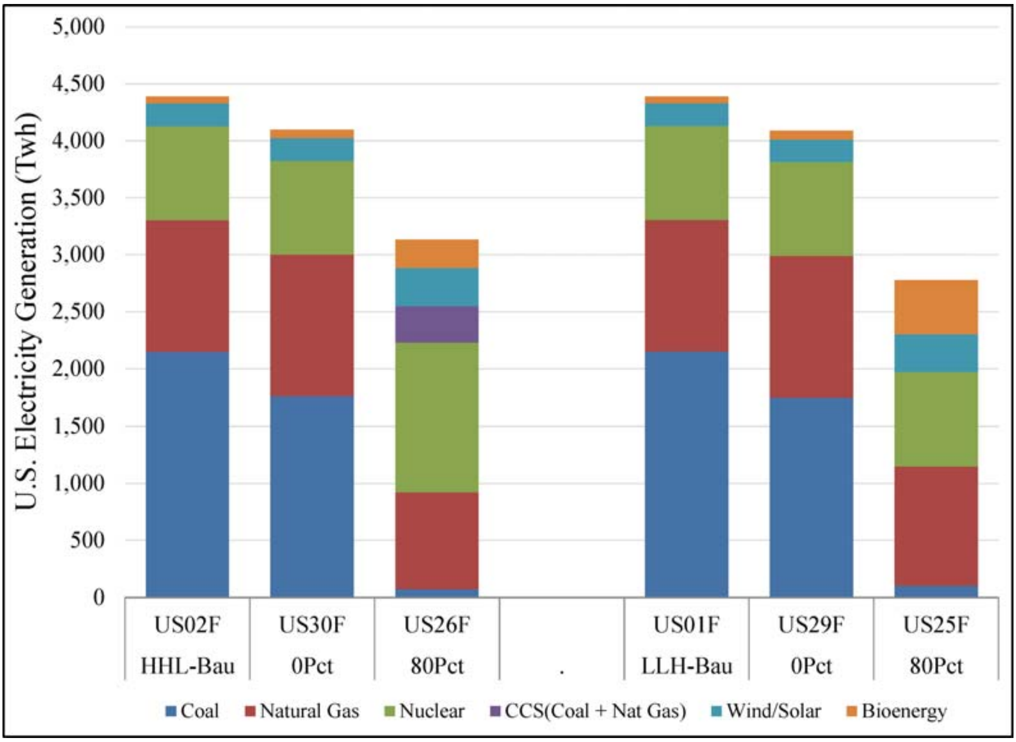
This behavior of quickly rising costs coincides with the increasing proportion of total emission reductions accounted for by the transportation sector relative to the electric sector as seen in Figure 9. This exponential increase in costs is a result of the need for more advanced technological solutions. Having a greater availability of nuclear generation and CCS, as in the HHL scenario, results in the knee occurring farther out in the abatement target spectrum than in the HLH scenario. This would seem to suggest that the payoff for investment in advancing nuclear and CCS technology is greater than a commensurate investment in the advance of renewable generation.

D. Electricity Market Impacts

Figure 12 shows the mix in electricity generation across select scenarios. The difference in impact on generation mix between the HHL and HLH scenarios is primarily seen at higher

14. In a cost-benefit setting, carbon mitigation can be thought of as the benefit of the abatement policies. N_{ew}ERA does not model health or other benefits related to reduction in GHG emissions and their contribution to GHG concentrations.

Figure 12: Total U.S. Electricity Generation in 2035 (TWh)



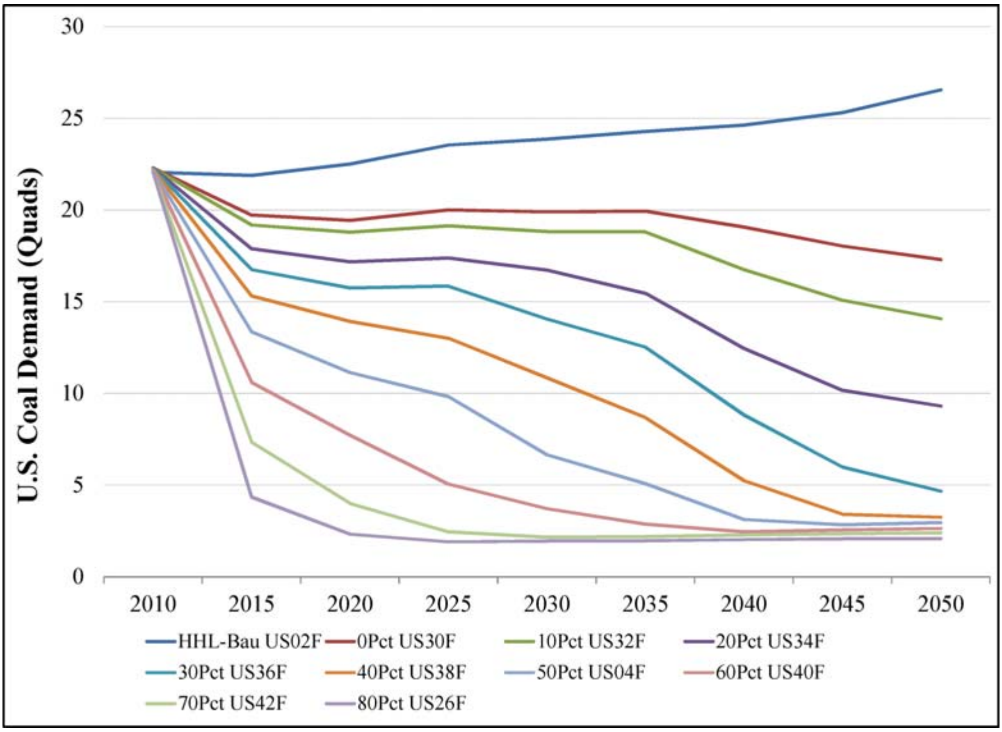
emissions reductions targets due to the redevelopment of the electric sector necessary to meet abatement goals. All scenarios involving cap-and-trade incur an economy-wide reduction in electricity demand and concurrent electricity generation due to the increased costs of electricity consumption from the policies. Because electricity is less carbon intensive than fossil fuels, there is some substitution from fossil energy to electricity in household consumption and industrial processes, but overall total demand for electricity falls. The drop in electricity demand is correlated with the increase in required emissions abatement.

The mix of electricity generation is similar in the two 0% scenarios because the limits on nuclear, CCS, wind, solar, and biomass are non-binding at this level of emission reduction. For example, the constraint under HLH of no CCS has no effect because the allowance price stays below the level necessary to make CCS cost-effective.

Under the 80% scenarios, however, the allowance price reaches levels in which all available low or zero carbon technologies are utilized. Therefore the difference in availability of low carbon technologies greatly affects the generation mix. In the 80% HHL scenario, nuclear generation increases by almost 500 TWh relative to the Bau scenario, while natural gas generation falls by approximately 300 TWh. In the 80% HLH scenario, nuclear generation remains level and natural gas generation only falls by about 110 TWh. In both the HHL and HLH 80% reduction scenarios coal generation almost entirely disappears from the overall generation mix. Both the HHL and HLH scenarios also see approximately the same increase in wind and solar generation of approximately 130 TWh.

In addition to the differences in nuclear and natural gas generation, the HHL 80% scenario has an additional 320 TWh of CCS generation and less than 200 TWh of new bioenergy generation

Figure 13: Total U.S. Coal Demand (Quads)



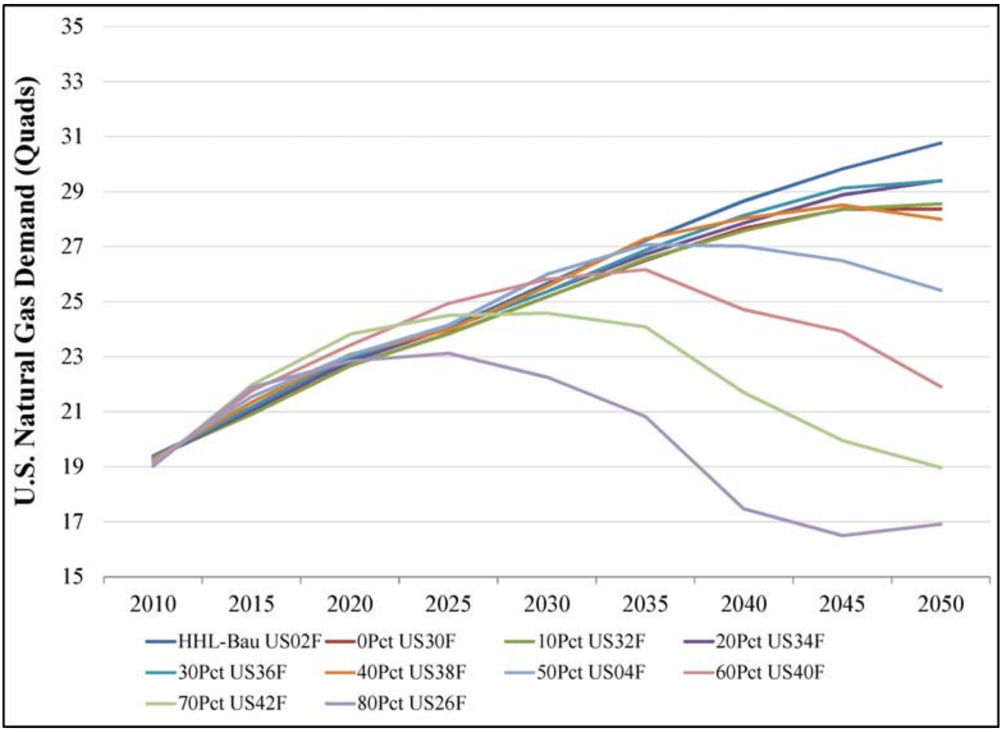
while the HLH 80% scenario has no CCS generation and approximately 410 TWh of new bioenergy generation relative to their Bau scenarios. Also, total electricity generation fell by only 1,250 TWh in the HHL 80% scenario compared to 1,600 TWh in the HLH scenario. This smaller relative decrease in overall electricity generation in the HHL 80% scenario is indicative of the lower overall welfare cost of the HHL combination relative to the HLH scenarios.

Figure 13 shows the change in total U.S. coal demand over time in the various HHL cap-and-trade policy scenarios. In all of the cap-and-trade scenarios coal demand declines dramatically as soon as the cap-and-trade program comes into effect in 2015. Given the model assumptions about the availability and cost of non-coal technologies, we find coal-fired generation decimated by 2025 under a 60% reduction and by 2045 under a 30% reduction.

Figure 14 shows the change in U.S. natural gas demand over time in the various HHL cap-and-trade policy scenarios. Demand for natural gas stays relatively constant in the early model years for each cap-and-trade scenario, with only small increases in demand seen for the 60%, 70%, and 80% reduction scenarios. In 2015 and 2020, natural gas demand in the scenarios exceeds that of the Bau because of the significant amount of coal to gas switching that occurs in the electric sector. 2025 is the first model year that significant reductions in natural gas demand from the Bau scenario are observed and this is only for the 80% reduction scenario.

Figure 15 shows the change in U.S. electric sector and non-electric sector natural gas demand over time for select HHL and HLH cap-and-trade policy scenarios. Natural gas demand in the non-electric sector remains similar to that of the Bau until the emission caps approach 50% below 2005 levels. Under these more stringent policies, the non-electric sector's demand for natural gas diminishes. The pattern of electric sector natural gas demand follows a more interesting path.

Figure 14: Total U.S. Natural Gas Demand (Quads)



For all scenarios, electric sector natural gas demand increases in the early years. It actually increases more dramatically as the policy requires more emissions abatement. In the 2020 to 2025 timeframe, the pattern reverses; electric sector natural gas demand continues to rise under the policies with less stringent caps and declines under policies with tighter caps. This pattern persists through 2050 for the HLH scenarios. Under the HHL scenarios, electric sector gas demand increases a bit in the last years as gas-fired CCS comes on-line.

E. Interaction Effects between Market-Based and Command-and-Control Regulations

Beyond the choice between market-based mechanisms or command and control regulatory mandates, there are policies that call for some sectors to contribute more than they might under either system and advocate combinations of market-based mechanisms and command and control regulatory mandates. When we examine the impact of combining mandates with cap and trade we see the predictable result that economic inefficiencies and market distortions are introduced into the system and welfare costs increase.

Figure 16 shows the inefficiency of layering on the command-and-control regulations to the pure cap-and-trade program (compare the square for the 50% scenario to the corresponding colored triangle), but of particular interest is the result that the command-and-control regulations, in particular the RPS policy, cause larger welfare losses under HHL because of there are fewer renewable resources under HHL than HLH (the HHL Combo scenario (red triangle) has a greater welfare cost than the HLH Combo scenario (blue triangle),. This result highlights two serious problems with command-and-control regulations. First, allowing the market to choose the technol-

Figure 15: Electric Sector versus Non-Electric Sector U.S. Natural Gas Demand by Scenario (Quads)

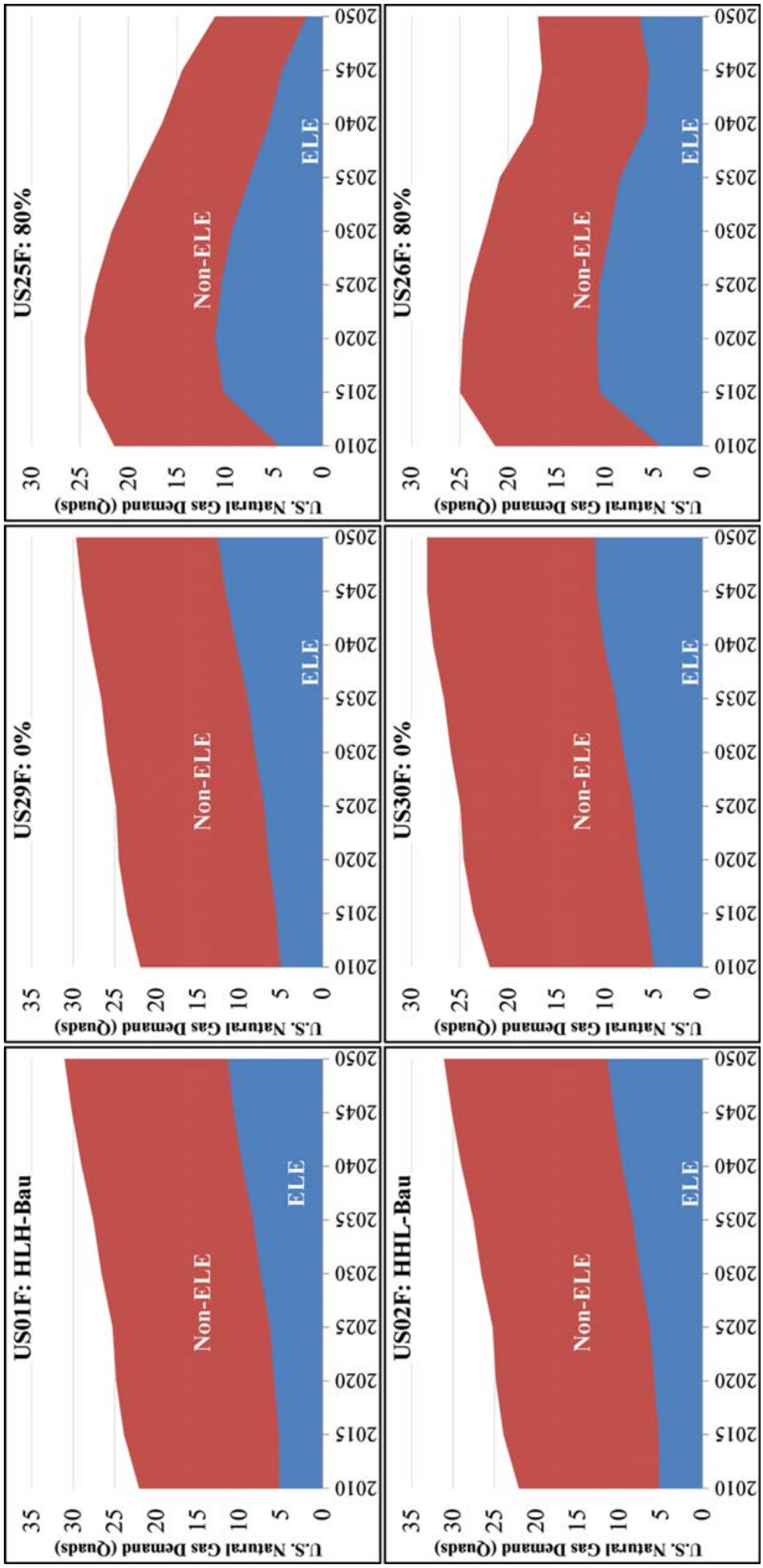
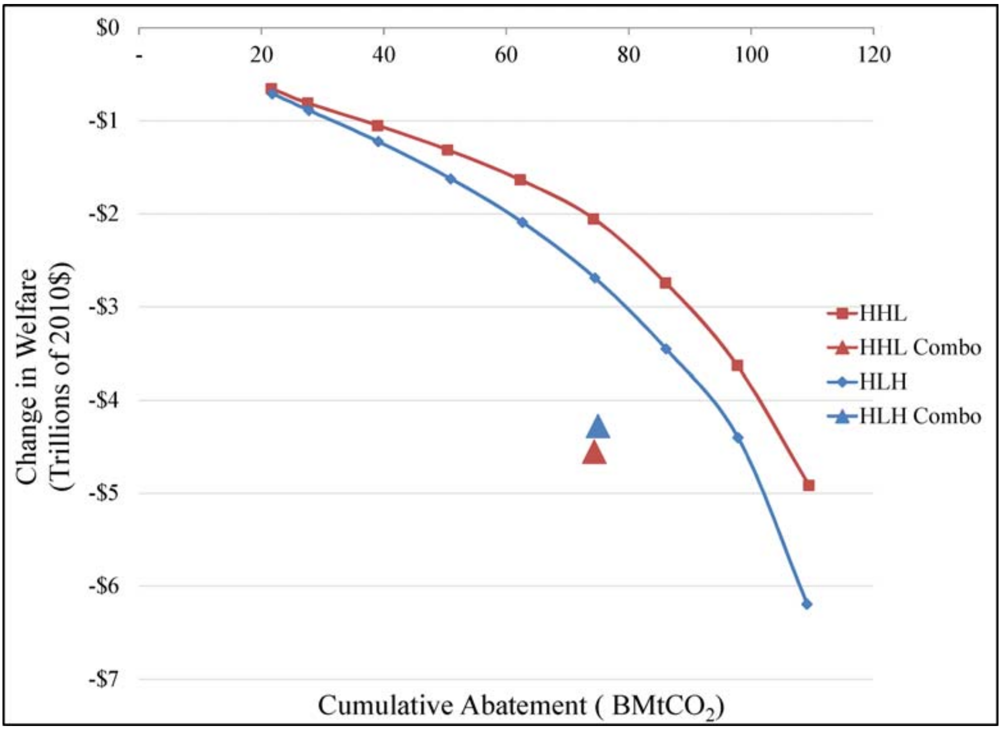


Figure 16: Changes in Welfare for Regulatory Mandates in Combination with Cap and Trade Relative to Efficient Frontier (Trillions of 2010$)

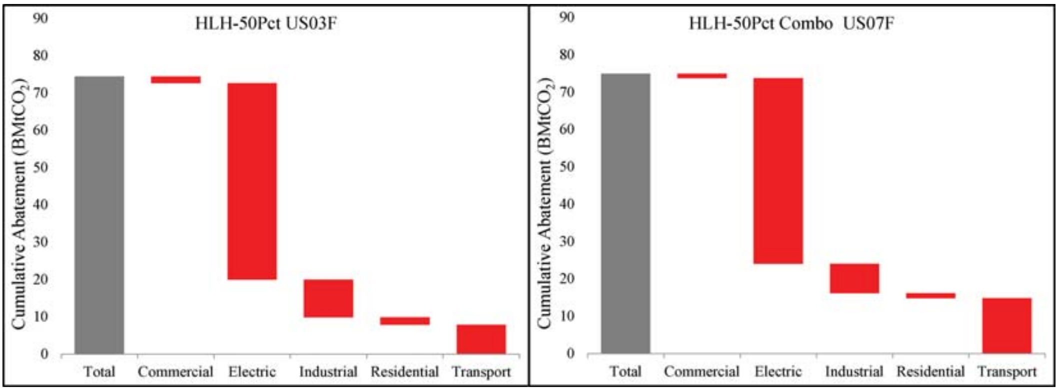


ogy to meet a particular environmental goal is generally better than regulators mandating particular technology to satisfy the goal, for when the technology is unavailable, the cost of meeting the environmental goal can rise dramatically. In our example costs rise by about $2.7 trillion dollars compared to $1.8 trillion dollars when the technology is available; and electricity demand is reduced by an additional ten percent from the demand in the pure cap-and-trade; whereas when the technology is available demand changes little from the level in the pure cap-and-trade program. Second, this result provides a good example of how overlapping and uncoordinated policy mandates introduce unforeseen economic inefficiencies into the economy and increase costs.

The primary reason for this inefficiency and resultant increase in costs is, as mentioned previously, the requirement for abatement from sectors that are not the least cost source of abatement potential. This can be seen with greater clarity in Figure 17 where moving from just cap and trade (US03F) to the combination scenario (US07F) creates a greater requirement for abatement from the transportation sector and less abatement from the electric, industrial, and residential sectors. Figure 10 shows the relative inefficiency of carbon abatement from the transportation sector due to the higher marginal cost of abatement in that sector. Increasing the required abatement from a sector with a higher marginal cost of abatement than one with a lower marginal cost will increase the total cost of abatement of a given policy or combination of policies.

Interestingly, even though total welfare costs increase when mandates are introduced within a cap and trade policy, the carbon price ends up being lower. The emission reductions mandated by the command-and-control policies reduce the need for price-induced reductions in emissions. Additionally, the command-and-control measures prescribe more expensive carbon emission re-

Figure 17: Relative Sectoral Share of Emission Reductions (in BMTCO$_2$) for Cap & Trade Scenario (US03F) and Regulatory Mandate and Cap & Trade Combination Scenario (US07F)



ductions than a market-based mechanism alone. The end result is that total emission reductions are the same, but the carbon price is lower and the total system cost is higher. This result provides a key insight that overall policy costs cannot be inferred from the CO_2 allowance price alone when non-market based policies are implemented together with a market-based policy. Figure 18 illustrates this tradeoff between a lower carbon price and increased cumulative welfare losses.

V. CONCLUSIONS

As discussion and debate of reducing emissions take center stage in the coming years, achieving the right combination of policy prescriptions and technology advances and usage will be vital in achieving significant reductions on U.S. greenhouse gas emissions, while minimizing economic costs. Of the 32 scenarios analyzed using the N$_{ew}$ERA model, those emphasizing market-based mechanisms clearly showed an efficiency advantage over command-and-control regulatory approaches. Layering on command-and-control polices on top of market-based polices clearly showed a loss in economic efficiency by increasing market distortions. Furthermore, technology applications that reduced emissions from electricity generation – particularly nuclear and end-use efficiency technologies – produced the largest, least-costly emissions reductions than increasing renewable based on the assumptions we made in the model.

As policymakers continue to pursue efficient, effective steps toward reducing greenhouse gas emissions, it is important for policy makers' to understand implication of market-based and command-and-control policies. As more and more command-and-control types of polices are being pursued in the U.S., this paper analyzed the interaction of these two different types of policy instruments. From an economic efficiency perspective, market-based solutions are always the least cost option. Policy makers should be mindful of potential unforeseen interactions between market-based and command-and-control policies, as demonstrated in this paper, and remember that shifts in technology usage – and development of new technology – are central to any successful emissions reduction effort.

ACKNOWLEDGMENTS

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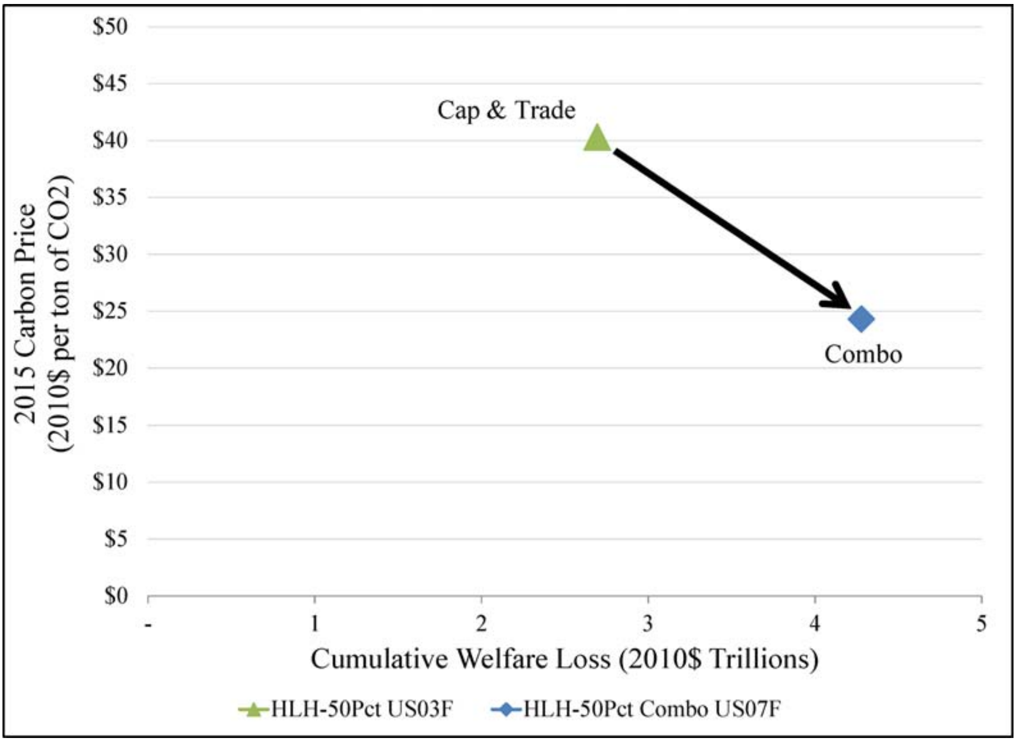
Figure 18: Comparison of Carbon Price and Cumulative Welfare Loss in Cap & Trade Scenario and Combo Scenario



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APPENDIX A: REGIONAL ELECTRICITY SECTOR RESULTS

The detailed treatment of the electricity sector within the N_{ew}ERA model allows for examination of electricity sector results at the level of each of the 32 power pools. By looking at results at this level of granularity, we can get a sense of the regional disparities in policy impacts as well as a general idea of where certain policy combinations can produce winners or losers depending on the circumstances of each pool and the policies in question. To provide some insight into key regional outcomes as a result of certain scenario policy combinations, we have included some heat maps showing differences in regional results of changes in electricity prices. Figure 19 through Figure 22 show the percentage change in wholesale electricity prices from the BAU in 2035 by demand pool.

One of the key takeaways can be seen in comparing the percentage price changes in Figure 19 and Figure 21, where we notice the electricity price change impact is greater in the US03F scenario where new nuclear and CCS generation is not available compared to the US04F scenario where it is. The greater necessity of relying on building renewables in US03F has more particular regional impacts in the Midwestern states relative to the rest of the country, although electricity prices are higher across the board.

Another interesting result demonstrated by these figures is that of the degree of price impact from layering on an RPS onto the cap and trade regime as seen in Figure 20 and Figure 22. The increase in price impacts when moving from US04F to US08F is far more significant than when moving from US03F to US07F, despite US04F having the smallest impact of these four scenarios to begin with. The reason for this lies in the application of the suboptimal RPS requirement in a scenario with fewer options for meeting renewable requirements and which already is capable of meeting its cap and trade restrictions through construction of more cost effective nuclear and CCS solutions.[15]

15. These heat maps are meant to demonstrate the N_{ew}ERA model’s ability to report regional results and the difference in impacts across regions. As for inferring which regions see the highest absolute rate increases, one would need to view heat maps showing changes in the absolute price of electricity. The included heat maps show the smallest percentage change in prices occurs on the West and East coasts, but the California and the Northeast are also the regions with the highest electricity rates. Therefore, the lower percentage increase in these regions may still mean they see the highest absolute changes in prices.

Figure 19: Percentage Change in Wholesale Electricity Price by Demand Pool in 2035, US03F

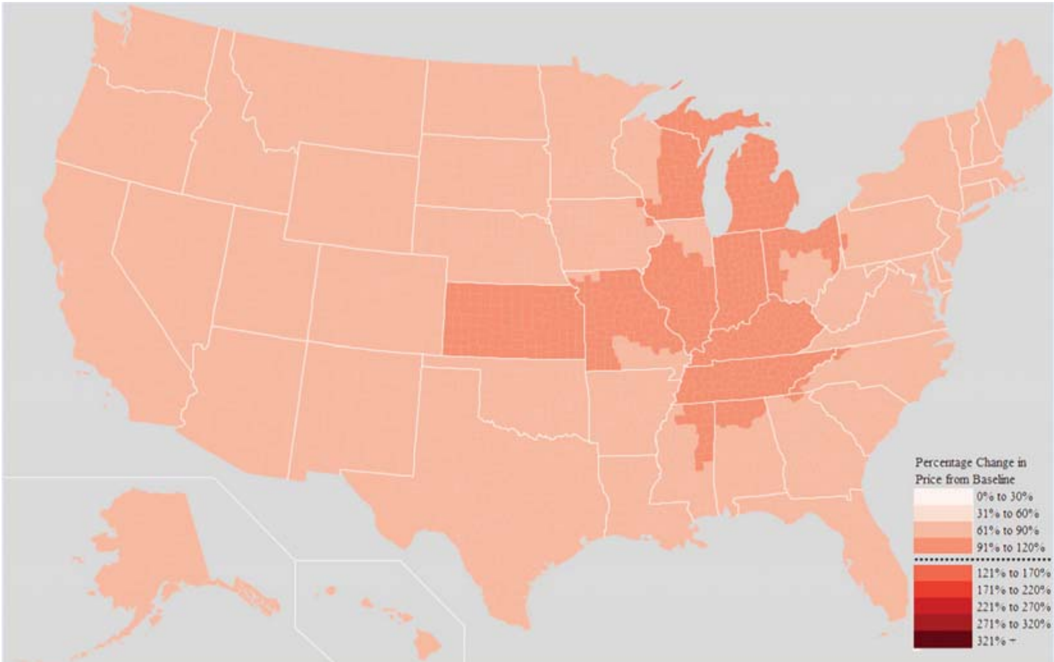


Figure 20: Percentage Change in Wholesale Electricity Price by Demand Pool in 2035, US07F

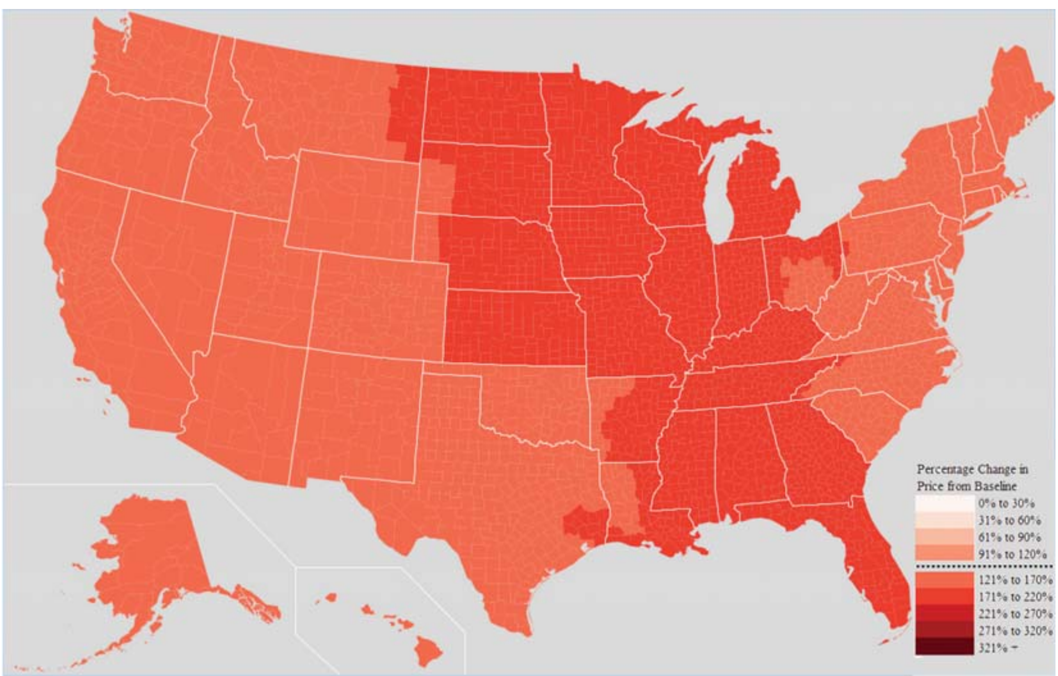


Figure 21: Percentage Change in Electricity Price (Wholesale plus RPS) by Demand Pool in 2035, US04F

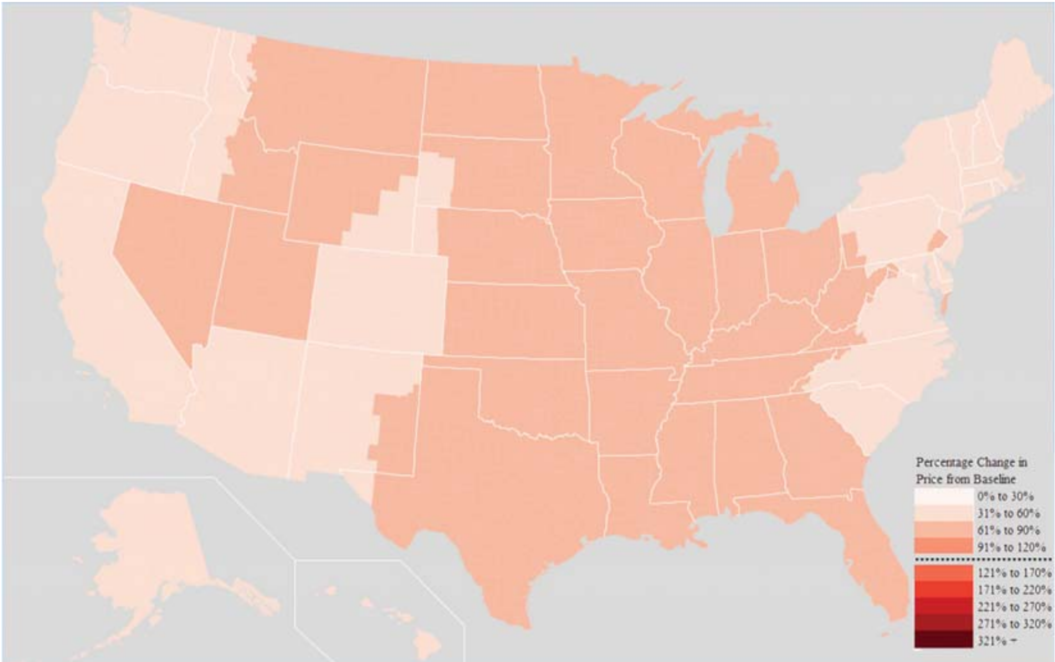
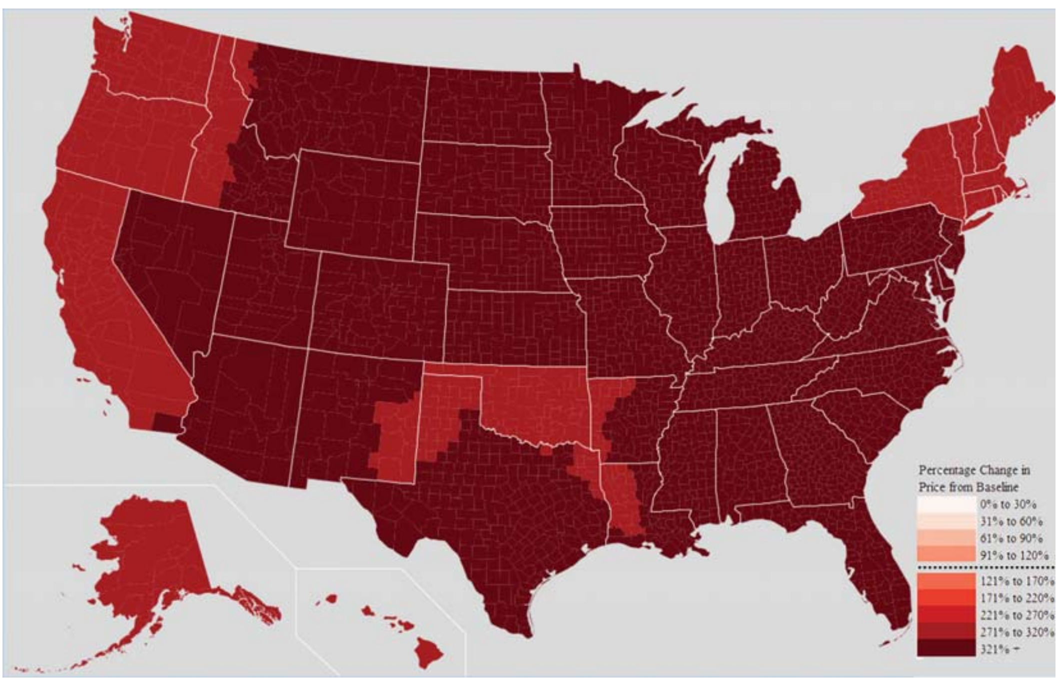


Figure 22: Percentage Change in Electricity Price (Wholesale plus RPS) by Demand Pool in 2035, US08F



Technology Assumptions and Climate Policy: The Interrelated Effects of U.S. Electricity and Transport Policy

Mark Jaccard and Suzanne Goldberg**

ABSTRACT

Although economists prefer a unique, economy-wide carbon price, climate policies are likely to continue to combine technology- and sector-specific regulations with, at best, some degree of carbon pricing. A hybrid energy-economy model that combines technological details with partial macro-economic feedbacks offers a means of estimating the likely effects of this kind of policy mix, especially under different scenarios of technological innovation. We applied such a model, called CIMS-US, in a model comparison project directed by the Energy Modeling Forum at Stanford University (EMF 24) and present here the interrelated effects of policies focused separately on electricity and transportation. We find that technological innovation encouraged by transportation regulation can inadvertently increase emissions from electricity generation and ethanol production to the extent that abatement from the regulation itself is effectively neutralized. When, however, regulation of electricity generation is combined with transportation policy or there is economy-wide carbon pricing, substantial abatement occurs.

Keywords: Climate policy, U.S., Electricity, Transport, Technological change

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INTRODUCTION

To reduce greenhouse gas emissions from the energy sector, U.S. policy makers would benefit from a clearer understanding of the interaction of several uncertain factors. What are the prospects for cost reductions and market penetration of different technologies in different but related sectors, such as electric vehicles and solar electricity? What will be the preferences of firms and consumers in the face of technological change and climate policy? How will regulatory policies perform relative to price-based policies? What will be the cost and energy price effects of achieving a given emissions target?

To address these questions, energy-economy modelers apply different types of models.[1] Some are technologically-explicit, focusing in detail on the current stock of energy-using equipment and the characteristics of existing or emerging technologies. Some have little or no technological detail, focusing instead on the responsiveness of the economy as a whole and individual sectors to climate policies. Some try to bridge these two perspectives, albeit with some important limitations.

1. The following discussion summarizes points made in numerous survey articles, an example being Hourcade et al., 2006.

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Conventional technology-explicit models have traditionally been referred to as bottom-up, engineering or technico-economic models. These represent the various energy end-uses in the economy and the technologies available to service them. Technology-explicit models are appropriate tools for examining the effect of new technological developments or policies that mandate a certain technological outcome, like a renewable portfolio standard that requires a rising share of renewable electricity, or a vehicle emissions standard that requires a growing market share for zero-emission vehicles.

However, their level of technological detail creates modeling challenges because they need detailed information on how firms and households make micro-economic decisions in choosing one technology over another. Most technology-explicit modelers use some kind of rule-of-thumb, suggesting for example that those technologies with the lowest financial cost should be preferred. Some compare this with an optimization algorithm that assumes an economy-wide cost-minimizing outcome in the selection of technologies. Unfortunately, this is unhelpful to policy-makers trying to assess how firms and households are most likely to respond to technology-focused policy, or even policy that combines an economy-wide emissions price with some technology-specific mandates. Finally, such models are usually partial equilibrium in that they fail to account for all feedbacks as the economy adjusts to a given policy, which can entail changes in the structure of the economy and its total level of output.

In contrast, models that are not technologically-explicit are typically referred to as top-down models. The standard approach is to apply computable general equilibrium (CGE) models that contain a set of elasticity parameters in order to simulate substitution between economic inputs and between final product demands.

Elasticities depict how a given increase in the price of an input like energy will lead to a given decrease in its market share relative to other inputs. This is an abstract way of representing a shift in the economy toward technologies that are more or less energy-intensive, or that use one form of energy instead of another. Since these models represent the economy at an aggregate level, it is not too difficult for them to encompass key indicators of macro-economic performance, including energy prices, capital costs, sectoral production costs, sectoral output, investment, and changes in economic output and welfare.

To the extent that their elasticities are estimated from past market responses, these models can provide useful information to policy makers. However, although these parameters may accurately depict past responses to price changes, they may be inaccurate in portraying the response in future periods, especially if the technology choice set is changing significantly. Historically-derived estimates for inter-fuel substitution for personal vehicles could be inaccurate for assessing the likely rate of uptake of electric cars since these were not a viable option for consumers during the historical period for which behavioral data are available. Likewise, elasticities for electricity generation options may not tell an accurate story when future options include renewable technologies that were less viable over the historical period.

Frustration with the deficiencies of these two conventional modeling approaches has led a growing number of modelers to develop hybrid variants that combine some aspects of the technology-explicit and the CGE models within the same framework. On one hand, a technology-explicit model might incorporate feedbacks between energy supply and demand and between sectoral production costs and sectoral output. On the other, a CGE model might incorporate detailed technological representation of electricity generation or personal vehicles in an ancillary sub-model that feeds into the general equilibrium solution.

CIMS-US is one of these hybrid models. It is technology-explicit, like a bottom-up model. But it simulates technology choices based on behavioral parameters estimated from discrete choice surveys of revealed and stated preferences, thus representing the micro-economic responsiveness of firms and households to changes in costs and regulations.[2] It also simulates shifts in service demand in response to changing service costs (for personal mobility for example) and shifts in industrial output for a change in production costs, thus representing in part the macro-economic responses to changing energy prices. It is, however, only partial equilibrium in that it lacks the full macro-economic linkages of a CGE model (Bataille et al., 2006).

In EMF 24, we applied CIMS-US to a range of scenario assumptions about energy technology development and U.S. energy and climate policy. A hybrid model like CIMS-US is particularly well-suited to exploring the possible effects of scenarios which combine assumptions about (1) technological innovation and commercialization, (2) technology- and sector-specific policies, (3) the sectoral interplay of these focused policies, and (4) the combination of these focused policies with an economy-wide carbon price resulting from climate policy.

To illustrate this attribute, we present in this paper a subset of results from EMF 24 that examine the effect on U.S. energy demand and emissions from accelerated technology development in the electricity and transportation sectors under different technology- and sector-focused policies, as well as an economy-wide carbon price. Our results depict, in particular, the interdependent relationship between low- and zero-emission technologies in the transportation sector and low- and zero-emission technologies in the electricity sector, as well as the effect of this relationship on national fuel demand and emissions, which can be both complementary and conflicting.

CIMS-US

The CIMS-US model is a hybrid technologically-explicit energy-economy model that considers behavioral realism in simulating micro-economic decision-making and some macro-economic feedbacks from service and production cost changes. The model uses a market share algorithm to simulate how consumers and firms select technologies and fuels under different regulations, energy prices and emission charges.

CIMS-US tracks the evolution of energy-consuming capital stock—and thus the energy, emissions, and cost implications of this evolution—from 2005 out to 2050. CIMS US has over 2000 end-use technology archetypes in its framework. Each technology archetype is characterized by financial costs (capital and operating costs), technology learning (reduction in costs from experience producing or using a new technology), intangible costs (non financial costs based on qualitative considerations such as technology performance), discount rates, energy requirements and the associated emissions output, product life times, and year of adoption (to enable capital vintaging). Parameters in CIMS have been estimated from historical data, stated and revealed choice research, including discrete choice surveys.

CIMS-US is a simulation model that iterates between energy supply and demand, as well as between this energy aggregate and the overall economy, in response to changing conditions (a carbon tax, a regulation) until a new equilibrium is found (which occurs when the direct and secondary responses to the initial change have occurred). Micro-economic choices for technologies and fuels are simulated based on minimizing financial and intangible costs, these latter the result of behavioral parameters estimated from discrete choice surveys (Mau et al., 2008).

2. Descriptions of CIMS-US and its parameter estimation are found in Jaccard (2009), Axsen et al., (2009), and Murphy and Jaccard (2011).

Technological change is stimulated in two ways: (1) by specifying the technologies that will become available in future time periods, such as in the *optimistic energy end use efficiency assumption*, or (2) by the CIMS market share algorithm via capital cost learning curves and declining intangible cost curves. Values for these parameters have also been estimated from discrete choice surveys.

THE SCENARIOS

We compare the results of five scenarios from EMF 24 that highlight the interaction of emissions and technological innovation in the personal transportation and electricity sectors, which result from alternative policy designs. The selected scenarios and their associated assumptions are presented in Table 1 and are described below. With the exception of US14, all scenarios are identical in their assumptions about technology:

- *Optimistic end use efficiency*—We are "optimistic" about the adoption of energy efficient end-use technologies and assume accelerated adoption of higher efficiency end-use technologies after 2020, reducing energy consumption 10% in the reference case from the base case.
- *No availability of carbon capture and storage (CCS).*
- *Low nuclear generation* – We assume no new nuclear capacity is developed after 2015, beyond what is planned and all nuclear plants retire at the end of their useful life (nuclear falls to 2–3% of total generation by 2050 from ~18% in 2010).
- *Optimistic renewable*—We assume "optimistic" or lower cost of production for wind and solar electricity as well as biofuels.

In US 14 we assume that carbon capture and storage, and new nuclear capacity are available.

Table 1: Selected EMF scenario assumption matrix

	Reference	Policy			
	US1	**US3**	**US5**	**US9**	**US14**
Technology Assumption					
End Use Efficiency	Optimistic	Optimistic	Optimistic	Optimistic	Optimistic
CCS Availability	*No*	*No*	*No*	*No*	Yes
Nuclear Availability	*Low*	*Low*	*Low*	*Low*	High
Renewables	Optimistic	Optimistic	Optimistic	Optimistic	Optimistic
Policy Assumption					
Cap & Trade	No	*Yes*	No	No	*Yes*
Transport Regulation	No	No	*Yes*	*Yes*	No
Electricity Regulation	No	No	*Yes*	No	No

Table 1 also shows the policy scenarios, which include both sector-specific regulatory and economy-wide carbon pricing policies:

- *Electricity Regulation*—A national renewable portfolio standard (20% by 2020, 30% by 2030, 40% by 2040 and 50% by 2050) and a coal phase-out policy (no new coal plants built after 2015).
- *Transport Regulation*—An emissions cap specifying a linear reduction in light duty vehicle emissions of 55% below 2010 levels by 2050. An emissions price is applied to all light-duty vehicle emissions to simulate this policy.
- *Economy-wide cap and trade policy*—A 50% reduction in greenhouse gas emissions below 2005 levels by 2050. An emissions price is applied to all emissions to simulate this policy.

The policy scenarios we review in this paper include a transportation regulation scenario (US9), a combined transportation and electricity regulation scenario (US5), and two economy-wide carbon pricing scenarios (US3 and US14). Under both policy approaches—economy-wide pricing and sector-specific regulations—our results illustrate the interdependent relationship between low- and zero-emission technologies in the transportation sector and electricity sector, and the effect of this relationship on national abatement.

SCENARIO RESULTS: THE REFERENCE CASE

In the reference case, energy consumption and emissions show fairly flat growth in the first two decades (2010–2030) of the simulation, followed by more rapid growth in the last two decades (2030–2050). Energy and emissions trends reflect increasing gains in energy efficiency outpacing economic growth (i.e., demand for energy services) in the early simulation periods, and the opposite in the later periods. By 2050 primary energy consumption is 34% and CO_2 emissions 18% higher than 2010 levels. Because the economy transitions to greater use of lower emissions fossil fuels (i.e., natural gas), emissions grow less than energy consumption.

Electricity generation and personal transport are two of the economy's biggest emissions sources, about 40% and 20% of national emissions respectively.[3] With current and projected trends in fuel use and technology efficiency, these sectors remain dominant in national emissions over the next four decades, from 2010 to 2050.

Demand for electricity is fairly constant to 2050. Annual average growth is about 2% a year, rising from 3,743 Twh to 6,202; the building sector, followed by the manufacturing sector account for the majority of this growth. In 2010 the generation mix is coal (50%), natural gas (20%) and nuclear (20%), with renewables at about 10%.[4] Due to lower natural gas prices anticipated in the short and medium term, we see a shift in generation away from coal to natural gas. By 2050 the generation mix is roughly 60% natural gas, 22% coal, 3% nuclear (determined by the technology assumption) and 15% renewable (see Figure 1). Despite increased generation, fuel switching in the sector results in only moderate growth in sector emissions. By 2050, emissions are 16% higher than in 2010 and represent 39% of national emissions.

Demand for personal travel, measured in person-kilometers-traveled, is anticipated to almost double by 2050. Due to existing fuel efficiency standards for light duty vehicles, emissions are expected to fall from current levels over the next two decades, but are anticipated to rise thereafter as the efficiency improvement in vehicle technology plateaus. Consequently, CO_2 emissions from transportation fall 11% between 2010 and 2030, and then rise 43% by 2050. Energy

3. Personal travel transport includes activity related to light-duty vehicle, transit, and personal air travel.
4. Renewables include large and small hydro, wind, solar, geothermal and biomass.

Figure 1: Reference case generation mix

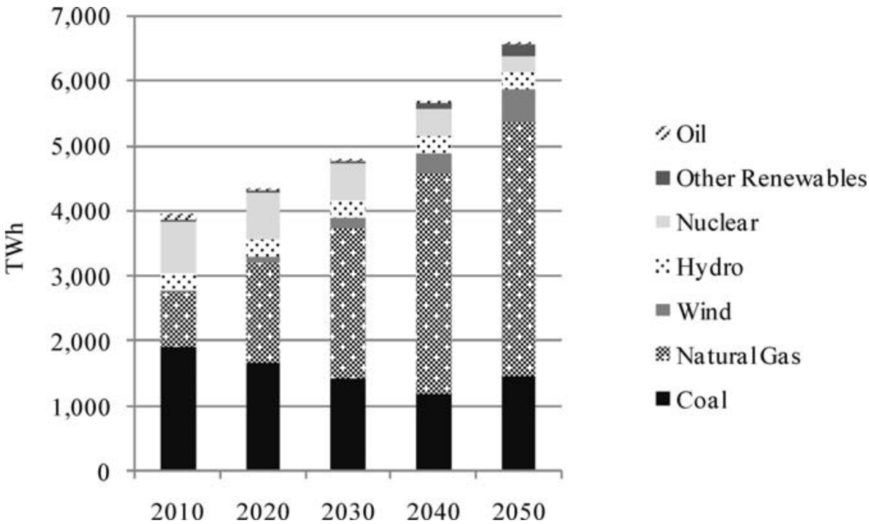
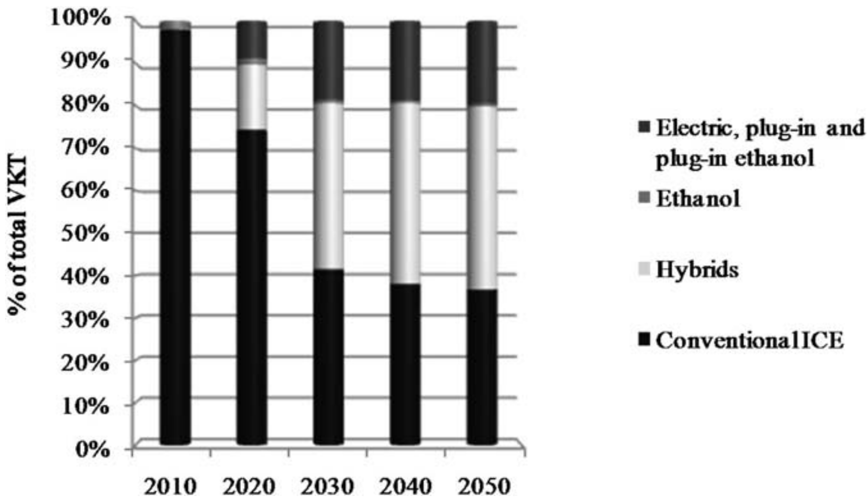


Figure 2: Reference case vehicle technology market shares (% of total vehicle kilometers traveled), 2010–2050



Note: "Plug-in" refers to vehicles that use both electricity and gasoline, and "plug-in ethanol" refers to vehicles that use both electricity and ethanol.

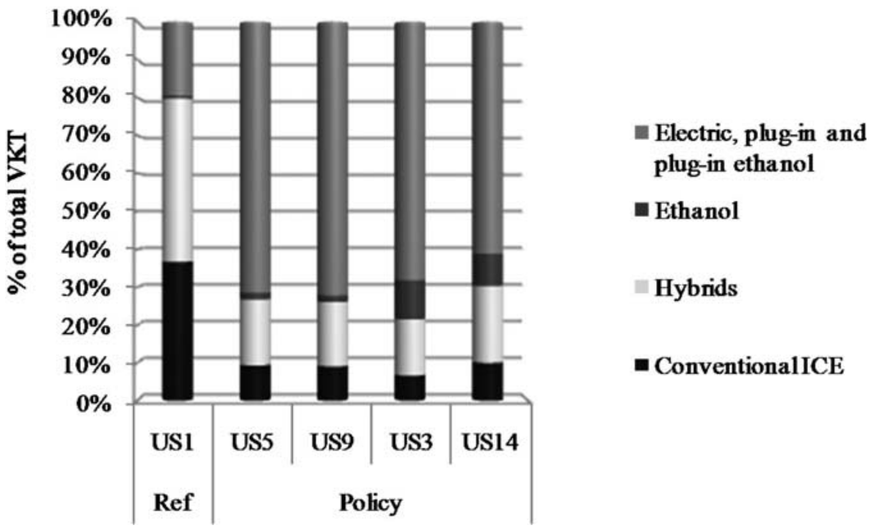
consumption shows a similar trend, although it is actually flat between 2010 and 2030 rather than slowly falling. Energy and emissions trends are defined by fuel efficiency standards, optimistic technology assumptions and increasing consumer confidence in newer technologies like hybrid and plug-in hybrid vehicles. By 2025, the share of conventional gasoline and diesel vehicles falls to about 50% of the total vehicle stock from 98% in 2010; the majority of lost market share is captured by gasoline hybrid vehicles (see Figure 2). Petroleum products maintain a dominant share of total personal transportation fuel consumption to 2050. However, shares of refined petroleum products decrease from 95% to 83% of total fuel use, as consumption of ethanol, and to a lesser extent electricity, increase.

SCENARIO RESULTS: TECHNOLOGY AND POLICY INTERPLAY

Policy Insights

- The two scenarios with sector-specific regulations—US5 and US9—specify outcomes in the personal transport and electricity sectors. In contrast, the economy-wide cap and trade scenarios—US3 and US14—do not specify how or which sectors should respond to the policy. Instead, abatement occurs in the sectors where it is cheapest to reduce emissions. Despite differences in policy design, technology adoption in personal vehicle travel and electricity generation is similar in all scenarios: greater adoption of alternative vehicles for personal travel and greater use of renewable energy for electricity generation.
- The regulations effectively induce abatement in the targeted sectors, but of course do not encourage abatement beyond what is specified by the regulation. Moreover, the transportation regulation in US9 actually increases emissions in the electricity generation and ethanol production sectors because of increased demand from technology innovation; greater adoption of electric and plug-in electric vehicles increase demand for electricity and greater adoption of ethanol vehicles increase demand for ethanol. Under this policy emissions in the two sectors increase to the point where abatement from the transport regulation has been effectively neutralized. However, policies that *do* anticipate some of these impacts, such as US5 which combines the transportation regulation with a renewable portfolio standard, see emissions from electricity generation fall with greater use of renewable power. The regulatory scenarios (US5 and US9) explored in this analysis do not target upstream emissions from the ethanol production sector.
- In the cap and trade scenarios emissions are reduced to levels below those achieved with the sector-specific regulations. In scenarios US3 and US14, a significant amount of abatement occurs in the electricity and personal transportation sectors, as well as in ethanol production. Technology adoption in the personal transport sector under the cap and trade policy is similar to that encouraged by the transportation regulation, and demand for electricity and ethanol increases. As with the combined transportation and electricity regulatory scenario (US5), cap and trade policies see the emissions impact of increased generation mitigated by greater renewable generation (and carbon capture and storage in US14). However, unlike US5, emissions from ethanol production are also mitigated.
- The policies examined in this analysis represent a diverse range of sector coverage and flexibility. According to the principle of equi-marginality, for a given level of abatement, the most cost-effective measures are those that impose identical marginal abatement costs on all options and agents of abatement (Baumol and Oates, 1988). Therefore, the greater the number of sectors and abatement options included in a policy, the more cost effective it will likely be. Conversely, the more constrained a policy is on these elements (i.e., coverage and flexibility) the less cost-effective. The transportation regulation examined in this analysis (US9) limits abatement options to vehicle technology innovation in the personal transportation sector and does not encourage abatement in other sectors of the economy. The economy-wide cap scenarios (US3 and US14) include abatement

Figure 3: Vehicle technology market shares (% of total vehicle kilometers traveled), all scenarios 2050



Note: "Plug-in "refers to vehicles that use both electricity and gasoline, and "plug-in ethanol" refers to vehicles that use both electricity and ethanol.

options from all sectors of the economy. In this study, we find that achieving an equivalent level of abatement in the transport sector is more costly under the transportation regulation (US9) than under the economy-wide cap (US3 and US14). For an equivalent abatement cost, emission reductions are one and a half times higher under the economy-wide cap than with the transportation regulation (direct emissions).

SPECIFIC RESULTS

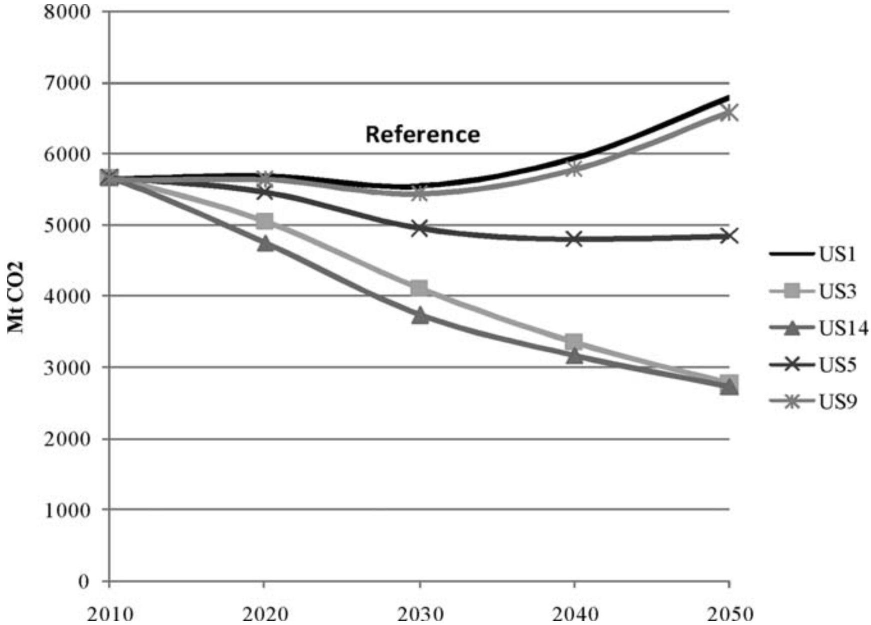
Vehicle Technology Adoption

Figure 3 shows vehicle technology market shares for all scenarios in 2050. The vehicle technology options explored in this paper were conventional gasoline and diesel combustion (of varying efficiency), electric, plug-in gasoline ("plug-in"), ethanol and plug-in ethanol vehicles. The EMF study treats the direct combustion of ethanol fuel as "zero emissions"; therefore, ethanol and plug-in ethanol vehicles are considered "zero-emissions vehicles" in this paper.[5]

In all policy scenarios, the adoption of conventional combustion vehicles decreases significantly, from about 98% in 2010 to under 10% in 2050. In response to aggressive emission constraints in the regulatory policy and high carbon prices in the emissions cap policy, adoption of "zero emissions" vehicles grows significantly. By 2050, the market share of "zero emissions" vehicles is at or above 70% across all scenarios. Hybrid vehicles, which contribute to early emissions reductions in the sector, fall from 43% of the total vehicle stock in the reference case to under 20%

5. Note: Upstream emissions from ethanol production are accounted for in the ethanol production sub-model in CIMS-US.

Figure 4: National emissions (Mt CO_2)



in the policy cases by 2050. All policies encourage similar vehicle technology adoption. The only major difference being slightly greater adoption of ethanol vehicles and lower adoption of electric vehicles in the economy-wide emissions cap scenarios, compared to the regulatory scenarios, because of higher electricity prices.

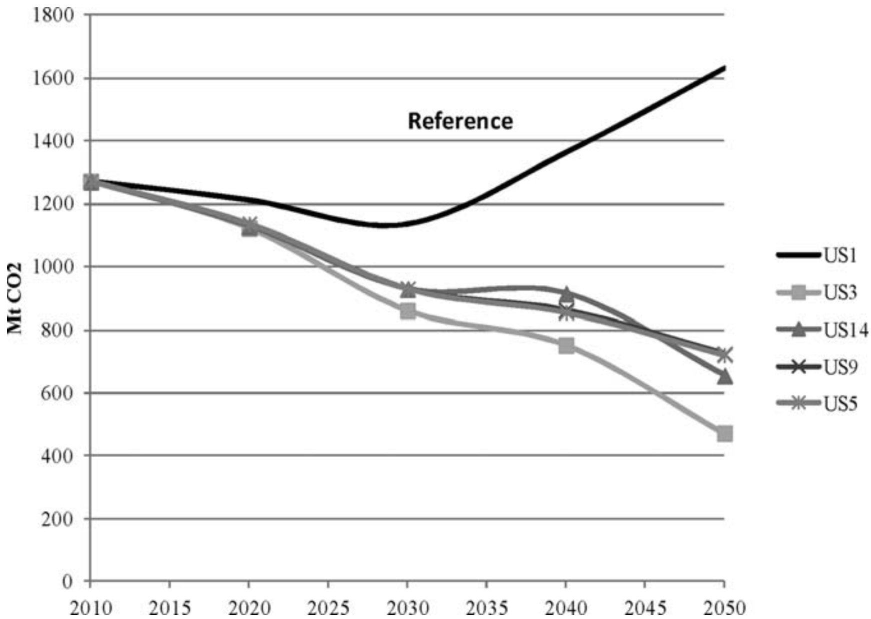
Electricity Demand

In the policy scenarios, demand for electricity increases from reference levels because of electrification in the personal vehicle fleet (i.e., greater adoption of electric, plug-in and plug-in ethanol vehicles) and, in the economy-wide cap scenarios, electrification in other sectors of the economy. Demand for electricity increases between 86% and 95% from 2010 to 2050—reference case demand growth is 66%. Even under the economy-wide cap, the majority of incremental electric demand comes from the personal transport sector. In addition to electrification, technology innovation in personal vehicle transport nearly triples demand for ethanol from reference levels in 2050.

Emissions

Figure 4 compares national CO_2 emissions in the reference case to the four policy scenarios. Overall, emissions in the policy scenarios fall relative to the reference case, from a 3% drop in the transport only regulation in US9 to a 60% drop in the cap and trade scenarios in US3 and US14. Emissions in the transport only regulation scenario (US9) fall only marginally relative to the reference case because abatement in the transport sector— ~ 900 Mt CO_2—is almost completely offset by an 18% increase in emissions from electricity generation and a tripling of emissions from ethanol production. In the other policy scenarios, generation from renewables and fossil fuels with carbon capture and storage mitigate the emission impact of increased electricity generation, and

Figure 5: Personal transport emissions (Mt CO_2)



emissions fall by more than half of their reference levels by 2050. For ethanol production, abatement actions, mainly fuel switching and carbon capture and storage application to steam generation, in the economy-wide cap scenarios reduce sector emissions to 2010 levels. As illustrated in Figure 5, personal transport emissions are reduced by more than 900 Mt CO_2 by 2050 in all four scenarios; the economy-wide cap scenarios achieve slightly greater abatement than the regulatory scenarios.

Electricity Generation Mix

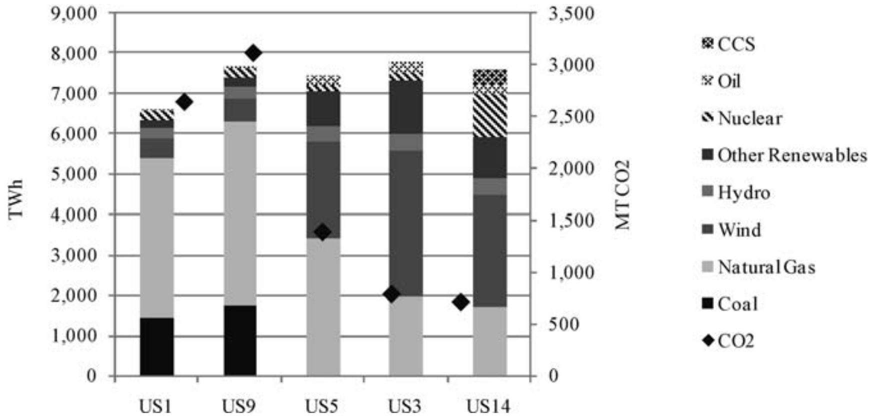
With the exception of the transport only regulation (US9), all scenarios see an increase in renewable generation, as well as a decrease in emissions intensity and sector emissions (see Figure 6). As US9 does not prescribe constraints on emissions from electricity generation, but does encourage significant electrification in the transport sector, emissions intensity and total sector emissions increase 2% and 18%, respectively, relative to the reference case in 2050. In the other policy scenarios, emissions intensity and sector emissions are reduced from reference levels by 50% or greater in 2050 due to increases in renewable and CCS generation, as well as the phase-out of coal generation. In the economy-wide cap scenarios, renewable generation increases more than in the combined transportation and electricity regulatory scenario, US5, with 5–20% more renewable generation (as a % of total generation) than US5. When CCS and nuclear are available (US14) under the economy-wide cap we see less renewable generation than when the use of CCS and nuclear are restricted.

The CIMS electricity model assesses renewable generation at a somewhat aggregate level. Consideration of intermittency and storage is not addressed at the level of specificity reflected in more detailed regionally-specific electricity models.

CONCLUSIONS

In the EMF 24 scenarios in this analysis we find that the technological innovation encouraged by transportation regulation can increase emissions from electricity generation and ethanol

Figure 6: 2050 utility generation and emissions (TWh & Mt CO_2)



production to the extent that abatement from the regulation is effectively neutralized. When regulation of electricity generation is combined with transportation policy, national emissions fall 30% from reference levels by 2050. Under an economy-wide cap, emissions fall even further to 50% below 2005 level by 2050 (60% below reference levels) with significant abatement in personal transport and electricity generation as well as in ethanol production. Note that in all scenarios direct emissions from ethanol combustion at the point source are considered "zero emissions".

Regulation is an effective approach to reducing carbon pollution at the sector level. However, when regulations are designed and implemented in isolation, they can actually increase emissions in sectors of the economy not covered by policy. Policies designed to cover all sectors in the economy, such as an economy-wide carbon price or coordinated multi-sector regulations, avoid these impacts. These are likely to be more effective in reducing emissions and more cost-effective.

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Greenhouse Gas Mitigation Options in the U.S. Electric Sector: A ReEDS Analysis

*Patrick Sullivan**, Caroline Uriarte*, and Walter Short**

ABSTRACT

We apply a U.S. electric-sector capacity-expansion and dispatch model to assess possible implications—changes in generation mix, system cost, CO_2 emissions, distribution of renewable energy deployment—of a set of potential greenhouse gas mitigation policy options over a range of technology projections. The model used, ReEDS, provides unique spatial and temporal detail to ensure electric-system constraints of reliable load provision are maintained throughout the system's transformation.

Keywords: Electricity capacity expansion, Greenhouse gas mitigation policy, Renewable energy technologies

http://dx.doi.org/10.5547/01956574.35.SI1.6

1. INTRODUCTION

This paper, written in conjunction with EMF 24, is a discussion of the implications of various climate policy options across a set of possible technology development pathways. The model, ReEDS, on which this analysis is based focuses on the modeling of renewable energy technologies and their integration into the electric sector under each of the policy and technology futures considered. Policy options include both technology standards—mandated targets for energy generation from clean or renewable sources—and carbon caps that we can roughly compare the efficiency of. Optimistic and pessimistic technology improvement and availability futures for low carbon energy sources allow investigation of the sensitivity of the mitigation pathways to technology development

ReEDS, in particular, brings a focus on renewable energy sources and integration to the EMF 24 questions. Renewable resource supply curves and detailed transmission representation allow us to suggest possible geographic distribution of renewable energy development and to show that greenhouse gas mitigation pathways for the electric sector can rely on a technologically and geographically diverse portfolio of investments. Similarly, the operational details and emphasis on maintaining electric reliability while integrating variable renewable resources allow us to discuss how the rest of the generating fleet responds to growth in renewable technologies under various policy options, and what renewable technologies contribute to or demand from the electric system as a whole.

2. OVERVIEW OF THE REEDS MODEL

The Regional Energy Deployment System (ReEDS) model is a long-term, capacity-expansion model for the deployment of electric power generation technologies and transmission in-

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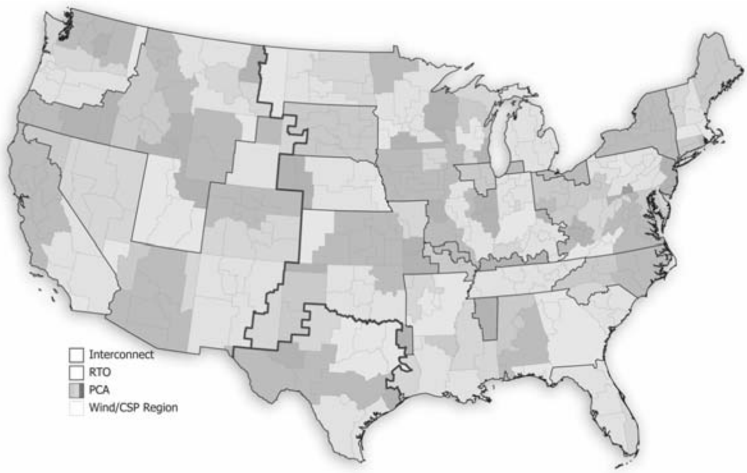
Figure 1: Map of ReEDS regional hierarchy



frastructure throughout the contiguous United States. Developed by the National Renewable Energy Laboratory (NREL), ReEDS is designed to analyze critical issues in the electric sector, especially those issues of particular importance to integration of variable renewable resources (Short, et al. 2011). This makes ReEDS particularly well-suited to analysis of potential energy policies, such as clean energy- and renewable energy standards or restrictions on carbon emissions.

ReEDS provides a detailed representation of electricity generation and transmission systems and specifically addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal load and generation profiles, variability and uncertainty of wind and solar power, and the influence of variability on the reliability of electric power provision. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary service requirements and costs.

A linear program optimization model, ReEDS determines potential expansion of electricity generation, storage, and transmission systems on a least-cost basis, considering load and reliability requirements, resource constraints, transmission limitations, and policy considerations. ReEDS is unique among capacity expansion models for its regional structure (see Figure 1) and statistical treatment of the impact of variability of wind and solar resources on capacity planning and dispatch. It is able to capture both the impact of resource uncertainty on system reliability and the ability of resource diversity to mitigate resource uncertainty not only because of its regional resolution, but also because it utilizes a sequential formulation: 23 optimizations performed seriatim, each reflecting a 2-year window of expansion planning. Problem coefficients can be updated between solves to capture non-linearities of system expansion: load growth; parameters reflecting integration concerns of wind and solar generators; retirements; transmission capacity changes.

Time in ReEDS is subdivided within each 2-year period: ReEDS distinguishes four seasons, each with a representative day comprising four diurnal time-slices. There exists one additional super-peak time-slice representing the handful of hours per year with the highest load. These 17 annual time-slices enable ReEDS to capture much of the dynamics of meeting electric loads that vary throughout the day and year.

ReEDS considers a full suite of generating technologies: hydropower, simple and combined-cycle natural gas, several varieties of coal, oil/gas steam, nuclear, wind, solar (both thermal and photovoltaic), geothermal, biopower, and a handful of electricity storage systems. Although ReEDS includes all major generator types, it has been designed primarily to address the market issues that are of the greatest significance to renewable energy technologies. As a result, renewable and carbon-free energy technologies and barriers to their adoption are a focus. Diffuse resources, such as wind and solar power, come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The model examines these issues, primarily by using a much higher level of geographic resolution than other long-term large-scale capacity expansion models: 356 different resource regions in the continental United States. These 356 resource supply regions are grouped into larger regional groupings—134 reserve-sharing groups (in ReEDS parlance, power control areas, or PCAs), states, North American Electric Reliability Council (NERC) regions (NERC 2010), and interconnects. States are also represented for the inclusion of state policies.

Much of the data inputs to ReEDS are tied to these regions and derived from a detailed geographic information system (GIS) model/database of the wind and solar resource, transmission grid, and existing plant data (Lopez et al. 2012). The geospatial detail of renewable resources enables ReEDS to consider tradeoffs between high-quality remote resource and accessible but lower-quality alternatives as well as the benefits of dispersed wind farms or solar power facilities for reducing the integration burden through resource diversification.

Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization. To allow for the evaluation of scenarios that might depart significantly from the base scenario, price elasticity of demand is integrated into the model and the exogenously-defined demand projection can be adjusted based on a comparison of the computed electricity price with an externally specified expected price.

In sum, ReEDS generates scenarios that describe type and location of conventional and renewable resource development over the next few decades; transmission infrastructure expansion requirements of those installations; composition and location of generation, storage, and demand-side technologies needed to maintain system reliability; and the overall cost of electricity supply.

3. SCENARIOS EXAMINED AND ASSUMPTIONS

The EMF 24 study was based on an ensemble of scenarios shown in Table 1. We examined a subset of these scenarios spread across both the technology and policy dimensions of the electric sector as shown by the ellipses overlaid on Table 1. Each of the scenarios is described by the set of policies it comprises and the assumptions of technology cost and availability. These are discussed in detail in the remainder of this section. The structure and focus of ReEDS precluded us from executing all of the scenarios, in particular those with transportation considerations. The particulars of how we implemented the requested scenarios in ReEDS are outlined in the following paragraphs.

Policy Dimension: The policy dimension allows a baseline (existing policies) scenario and a range of possible mitigation policies.

- **Baseline Scenarios:** The baseline scenarios assume no comprehensive national climate policy but do include existing policies that might influence GHG emissions in the electric sector. For ReEDS, this includes state renewable portfolio standard (RPS) requirements and limits on emissions of SO_2.

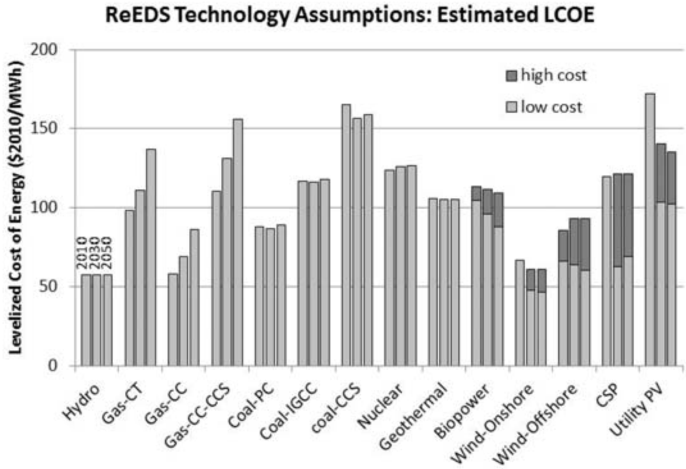
- **Carbon Reduction Cap-And-Trade Policy (C&T):** Cap-and-trade policy scenarios are characterized by a national policy that requires a linear reduction in GHG emissions from the electric sector from baseline levels in 2012 to the target level (X% below 2005 emissions) in 2050. These scenarios include only emissions directly associated with electricity generation: land-use change and other energy-related emissions (e.g. transportation, fuel extraction) are not considered. Whereas the EMF guidelines permit banking of carbon credits but no borrowing, ReEDS allows neither; nor does it allow alternative compliance payments or other offset schemes. CO_2 is the only GHG considered.
- **Renewable Portfolio Standard (RPS):** The RPS requires renewables (including hydropower and biopower) to provide 20% of national electricity generation by 2020, 30% by 2030, 40% by 2040, and 50% by 2050 with no banking or borrowing.

Table 1: EMF-24 Scenarios.

Technology Dimension								
	Optimistic	**Single Technology Scenarios**				**Combined Sensitivities**		**Pessimistic**
End Use Technology	Optimistic	Pessimistic	Optimistic	Optimistic	Optimistic	Optimistic	Pessimistic	Pessimistic
CCS	Optimistic	Optimistic	Pessimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Pessimistic
Nuclear	Optimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Pessimistic	Optimistic	Pessimistic
Wind & Solar	Optimistic	Optimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Optimistic	Pessimistic
Bioenergy	Optimistic	Optimistic	Optimistic	Optimistic	Pessimistic	Optimistic	Optimistic	Pessimistic
Policy Dimension								
Baseline	US13F	US15F	US17F	US19F	US02F	US01F	US21F	US23F
0% Cap & Trade					US30F	US29F		
10% Cap & Trade					US32F	US31F		
20% Cap & Trade					US34F	US33F		
30% Cap & Trade					US36F	US35F		
40% Cap & Trade					US38F	US37F		
50% Cap & Trade	US14F	US16F	US18F	US20F	US04F	US03F	US22F	US24F
60% Cap & Trade					US40F	US39F		
70% Cap & Trade					US42F	US41F		
80% Cap & Trade					US26F	US25F		
CAFE					US10F	US09F		
RPS					US12F	US11F		
CES					US28F	US27F		
CAFE + RPS					US06F	US05F		
CAFE + RPS + 50% C&T					US08F	US07F		

Notes: Those scenarios analyzed in this paper are darkly shaded.

Figure 2: ReEDS technology assumptions by technology: 2010, 2030, 2050



Notes: For renewable technologies with two estimated LCOE, the low cost represents the "optimistic" scenarios; high cost, the "pessimistic" scenarios.

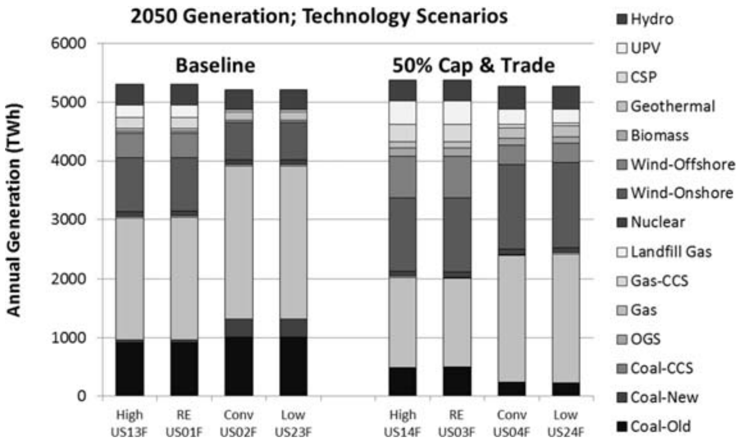
- **Clean Electricity Standard (CES):** This policy is similar to the RPS, but also includes nuclear power, fossil electricity with carbon capture and storage (CCS; credited at 90%), and natural gas (credited at 50%) in the "clean" portfolio. Both new and incremental generation from all eligible generation types may receive credit. Because many additional sources are allowed to receive credit, the targets are defined as linearly increasing from reference levels of 42% in 2012 to 50% by 2020, 60% by 2025, 70% by 2030, 80% by 2035, 90% by 2040, and constant thereafter. Banking and borrowing are not allowed.

Technology Dimension: The technology dimension of this analysis explores "optimistic" and "pessimistic" projections for technology types. ReEDS inputs include assumptions for technology cost and performance for the set of generating, storage, and transmission options available to the model. Base assumptions for technology cost and performance over time are derived from estimates from Black & Veatch (Black & Veatch 2012). For this analysis, ReEDS has a pair of technology cost/performance or availability options for CCS, nuclear, and renewable technologies:

- For CCS and nuclear, the "optimistic" cases use cost/performance assumptions from Black & Veatch while the "pessimistic" cases, in accordance with the EMF guidelines, assume that CCS and nuclear options are unavailable. All scenarios assume a phase-out of existing nuclear plants through retirement after 60 years of operation.
- For renewable technologies—"wind & solar" and "bioenergy"—the "pessimistic" cases use the Black & Veatch cost/performance assumptions, while the "optimistic" cases use lower-cost assumptions defined by NREL technology goals.

Figure 2 shows an estimate of the levelized cost of energy (LCOE) for various generating technologies in ReEDS. LCOE, not a direct input in ReEDS, is a function of capital, operating, and

Figure 3: Comparison of 2050 generation by prime mover; baseline and 50% cap & trade policies, across technology assumptions



fuel costs along with an expectation for utilization factor and financing assumptions. For example, the increase in the cost of gas generation over time reflects that ReEDS assumes natural gas fuel costs will rise between 2010 and 2050. LCOE for optimistic and pessimistic cost assumption sets are shown for wind, solar, and biopower technologies.

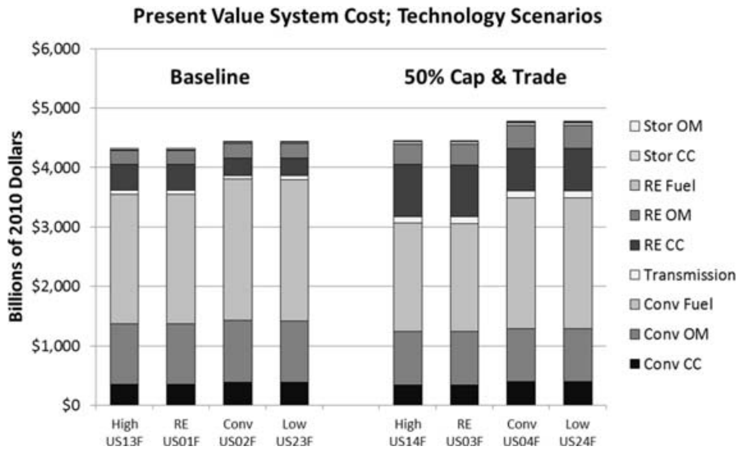
There are four sets of assumptions in the technology dimension: “High,” in which all technologies get their optimistic cost/performance assumptions; “RE” (renewable energy), wherein wind and solar get optimistic assumptions but CCS and nuclear, pessimistic; “Conv” (conventional energy), optimistic for CCS and nuclear, pessimistic for wind and solar; and “Low,” pessimistic for all. The Conv scenario uses the Black & Veatch assumptions for all technologies so matches best with the ReEDS standard assumption set.

4. RESULTS

4.1 Technology scenarios

Using the baseline and 50% cap & trade scenarios as the core, we explore how policy scenario outcomes are affected by the technology improvement and availability pathways. Comparing baseline and 50% cap & trade policies across the range of technology assumptions (Figures 3 and 4), a few things stand out, primarily that the availability or unavailability of nuclear and CCS technologies has minimal impact on the result. We do not expect to see CCS in the baseline scenario because, in the absence of a carbon signal, coal-CCS and gas-CCS are dominated by their non-sequestering counterparts, and nuclear power is similarly more-expensive than modern pulverized coal under these cost assumptions (see Figure 2). Even in the 50% carbon cap scenario, however, mitigation is accomplished through routes other than nuclear and CCS: a substantial amount of fuel-switching from coal to natural gas, and an expansion of renewable generation. In the Conv and Low cap & trade scenarios, 44% of generation comes from non-hydro renewables in 2050. In those same scenarios, coal contributes one-sixth of the energy in 2050 that it does in the baseline scenario with the same technology assumptions.

Figure 4: Comparison of present value of total system cost to 2050; baseline and 50% cap & trade policies, across technology assumptions



Notes: "OM" designates operations and maintenance costs; "CC" denotes capital cost.

Another notable observation across technology assumptions is that while wind and solar technologies both benefit from lower cost assumptions, gains are larger for the solar technologies (utility-scale photovoltaics, UPV; and concentrated solar power, CSP) and offshore wind than for onshore wind. In fact, in the 50% cap & trade scenarios, there is more generation from onshore wind in the scenarios with the higher costs. The explanation for this is that the relative cost reductions for onshore wind in moving from the higher to lower costs are smaller than those for other renewable technologies, and those greater cost reductions allow solar and offshore technologies to increase their contribution, compared to onshore wind.

Turning to system cost (Figure 4), we see that—in both the baseline and cap & trade scenarios—optimistic renewable costs lower total system costs by reducing fuel expenditures. Conventional capital and operational costs are largely flat across technology assumptions, but fuel costs are 9% lower in the baseline scenario and 17% lower in the cap & trade scenario under "optimistic" renewable assumptions. Another observation is that transmission costs nearly double in the cap & trade scenarios compared to the baseline but still represent only 2.5% of total system costs. The consistently lower electric demand in the Conv scenarios compared to the RE scenarios (Figure 3) is a direct result of higher system costs—which drive electricity prices up, depressing demand.

4.2 Policy scenarios

In the policy dimension, we compare the four non-baseline policies introduced in section 3: 50% cap & trade, 80% cap & trade, RPS, and CES. Figures 5 and 6 are arranged in scenario pairings: RE and Conv technology pathways for each of the four policies—illustrating again how different technology pathways can create a range of outcomes for a given policy. For instance, while the RPS does not directly affect coal/gas competitiveness, and their costs do not change across technology scenarios, there is a shift from coal to gas when renewable costs are lower. This secondary shift is a result of the increase in generation from variable renewable technologies that requires a more-flexible balance-of-system, which favors gas over coal. In contrast, in the 50% C&T scenario, lower renewable costs allow more coal back into the system, the opposite of the

Figure 5: Comparison of 2050 generation by prime mover; set of policy options, for RE and Conv technology assumptions

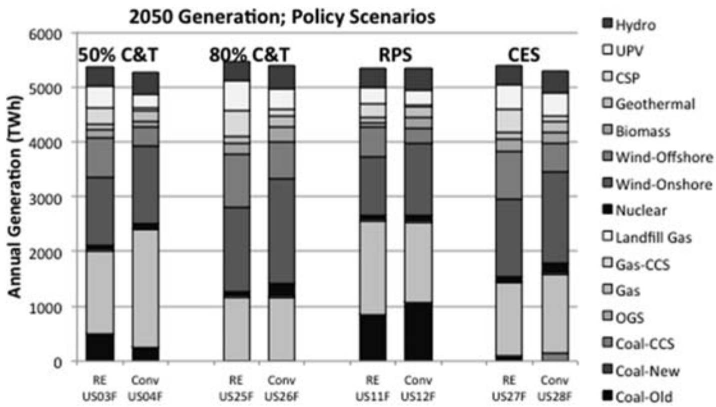
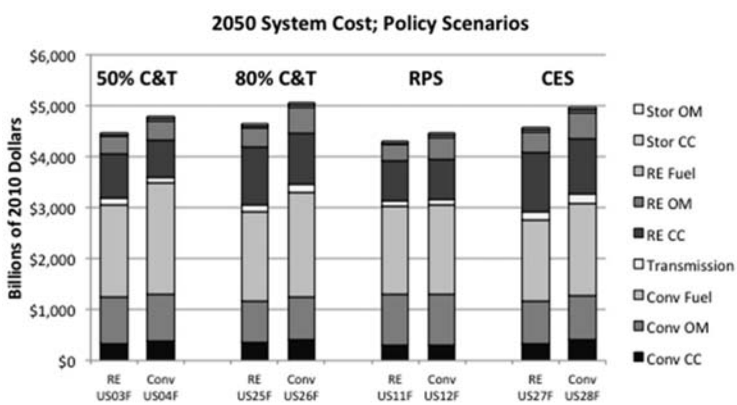


Figure 6: Comparison of present value of total system cost to 2050; set of policy options, for RE and Conv technology assumptions

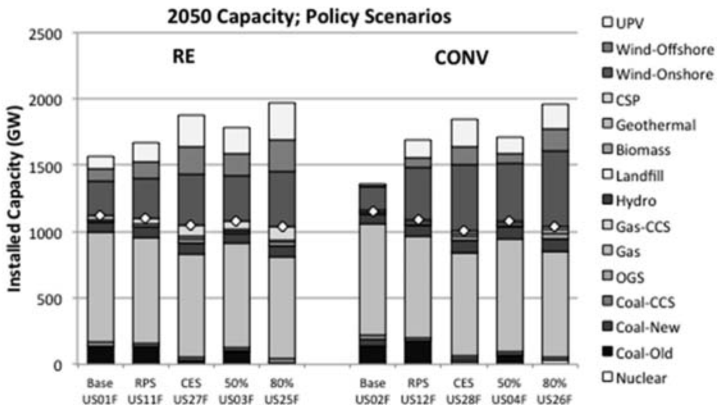


effect of lower renewable costs under the RPS. The mechanism here is that the additional renewable generation releases pressure on carbon emissions somewhat, opening up some of that headspace to coal. Notably, all of these scenarios use the same fuel price assumptions; alternative natural gas price scenarios, in particular, would likely result in somewhat different development pathways.

Comparing the 50% and 80% cap & trade scenarios, it is apparent that the more-stringent carbon cap drives non-capture coal out of the system. The carbon signal is also large enough in the 80% case to drive expansion of the nuclear fleet (the 80% C&T Conv scenario has three times the nuclear output of the baseline and 50% scenarios) and, while it is too small an effect to be seen in the figure, both coal- and gas-CCS see limited deployment under favorable technology assumptions and the strict carbon cap.

As with the baseline and 50% cap & trade scenarios, the three new policy options presented in Figure 5 all result in higher costs with the Conv technology costs compared to the RE technology costs. Looking across policy options, there is a notable increase in cost-sensitivity to technology availability with increasing mitigation demand. While the baseline policy has only a 3% difference

Figure 7: Comparison of installed thermal capacity and total capacity across scenarios.



Notes: The diamonds note the amount of installed thermal capacity.

in cost between the RE and Conv scenarios, the 50% cap & trade has a 7% spread and the 80% cap & trade, 9%. The direction of the difference, RE being less expensive than Conv, is a result of the particular technology cost projections used in these scenarios rather than fundamental to the policies: more-competitive thermal mitigation options could shrink or reverse the cost relationship.

As was seen in Figures 3 and 4, the 50% cap & trade scenario prompted fuel-switching and an increase in renewable installations and the 80% cap eliminated coal from the generating mix. The reduction in options embodied by the shift away from coal to renewable sources makes the system more sensitive to the cost of the renewable technologies. This is especially true in this set of ReEDS scenarios in which nuclear and CCS mitigation options are bit players. Were we also exploring sensitivity to natural gas prices, we would likely find that the price sensitivities of policies increased even further.

4.3 Capacity value of variable renewable technologies

The primary variable renewable resources are developed in these scenarios primarily to displace Comparing installed capacity in the baseline and policy scenarios allows us to estimate the ability of variable renewables to displace conventional capacity. The North American Electric Reliability Corporation (NERC) requires power system operators to carry or contract for sufficient firm capacity to meet expected peak load considering risk of outages and other contingencies (this concept is "resource adequacy"). ReEDS includes this requirement in its formulation and incorporates statistical calculations to appraise how wind and solar investments contribute toward these adequacy requirements.

Wind and PV technologies only produce power when the wind blows or sun shines, respectively, so can not always be relied upon to provide power at times of high load. Nevertheless, as discussed by Kahn (1979), Milligan et al (2000), Nanahara et al. (2004), and others, a set of geographically distributed wind and solar facilities can behave in a more statistically reliable manner, including by contributing toward adequacy requirements, a quantity known as capacity value. Figure 7 shows the 2050 total installed capacity across ten scenarios. While total capacity rises with the renewable requirement, the amount of thermal (used here to mean everything except wind and PV) capacity decreases from the base case. By comparing the displaced conventional capacity to the additional installed variable renewable capacity, we can estimate the capacity value for the bulk variable renewable fleet. For the eight non-baseline scenarios considered here, the bulk capacity value for additional variable renewable capacity ranges from 16% to 23%. These capacity value estimates are comparable to those found in the Western Wind and Solar Integration Study (GE Energy 2010). Despite being built primarily for energy requirements, the variable renewable generators displace substantial amounts of conventional capacity: 147 GW in the Conv CES scenario.

ReEDS is granted two concentrated solar power (CSP) options: with and without storage. CSP without storage is assumed to be a variable resource technology like wind and PV, while CSP with thermal storage—required to have a 6-hour reservoir—is considered a dispatchable, thermal resource. In these scenarios, nearly all CSP built was constructed with thermal storage, so for this capacity value analysis, we include CSP capacity as part of the thermal fleet, not among the variable resources.

4.4 Geographic distribution of variable renewable technologies

The United States is endowed with substantial, high-quality renewable energy resources: the Midwest and Great Plains are known for their wind resource potential, swaths of the southern tier of the country have substantial solar potential, and long coastlines, especially on the eastern seaboard allow for the possibility of large-scale offshore wind development there. In addition, the western states have substantial geothermal resource, and much of the country is capable of producing biomass feedstocks for biopower production. The policies evaluated for EMF 24 all induce substantial renewable energy investment in ReEDS scenarios, and ReEDS selected a portfolio of resources to fulfill renewable requirements and carbon mitigation targets.

Along with diversifying across technologies, ReEDS developed renewable resources geographically distributed around the country. Figure 8 shows how development of the four wind and solar technologies are spread across the country in a set of policy scenarios: major onshore wind development through the central regions, offshore wind on the eastern seaboard, CSP in the southwest, and PV spread across the southern states. Even before considering contributions from biopower, geothermal, and hydropower, all regions obtain substantial investment in renewable power in the cap & trade scenarios. Nine of the eleven of the regions even see substantial variable-renewable investment in the two baseline scenarios.

While geothermal and biopower investments are not shown on the map, those resources are also substantial contributors across the country. Six western states see geothermal development, and 41 out of the 48 contiguous states generate electricity from biomass by 2050 in the cap & trade scenarios.

4.5 Carbon Mitigation

That the dominant mitigation options in these scenarios are renewable technologies is reflected in Figure 9 wherein RE scenarios have lower marginal carbon abatement costs than their Conv counterparts in corresponding cap & trade scenarios. The 0% cap & trade scenarios require out-year electric sector carbon emissions to be no greater than 2005-levels. The RE 0% scenario has no carbon price after 2040 because it meets the flat emissions target with no additional cost. This can be seen in Figure 10, where the baseline CO_2 emissions level with RE costs falls below the 0% cap line. An implication of this is that given sufficiently competitive renewable energy technologies, the electric sector can reduce GHG emissions from present-day levels even in the absence of a nationwide mitigation policy.

Figure 8: Map of geographic distribution of installed capacity of wind and solar technologies in 2050 in selected EMF-24 scenarios

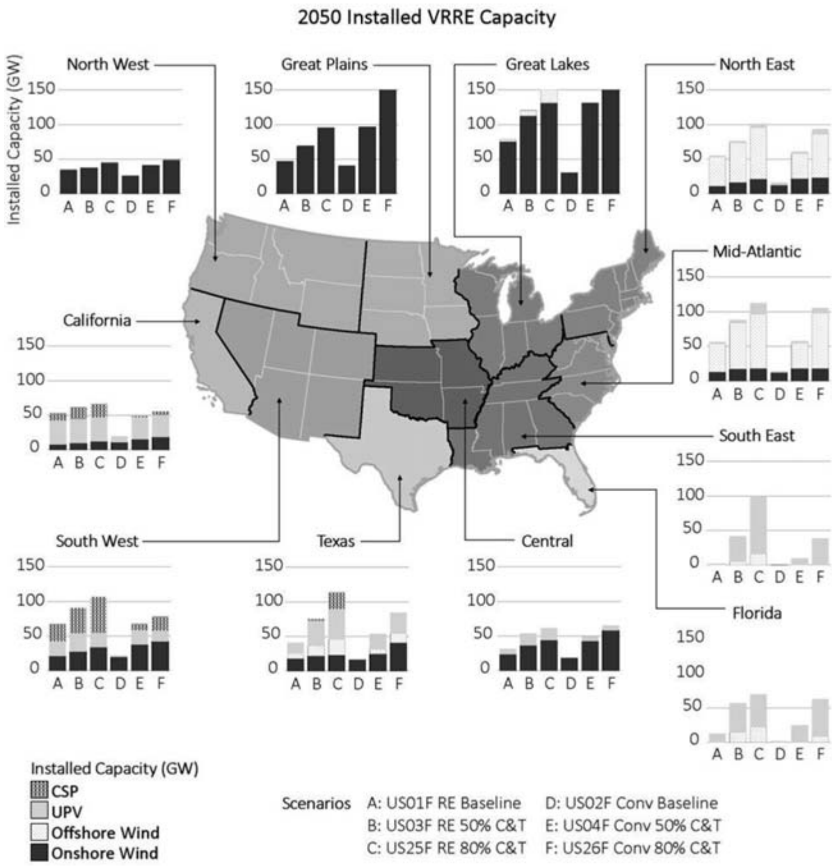


Figure 9: Marginal carbon abatement cost for the set of cap & trade scenarios, for RE and Conv technology assumptions

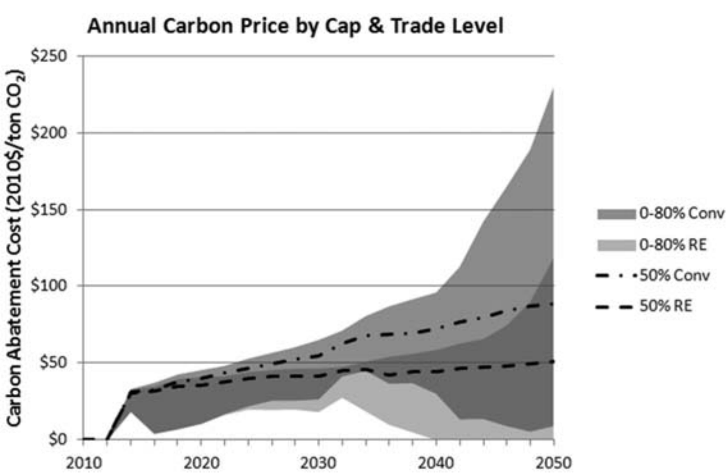


Figure 10: Annual electric-sector CO_2 emissions by scenario

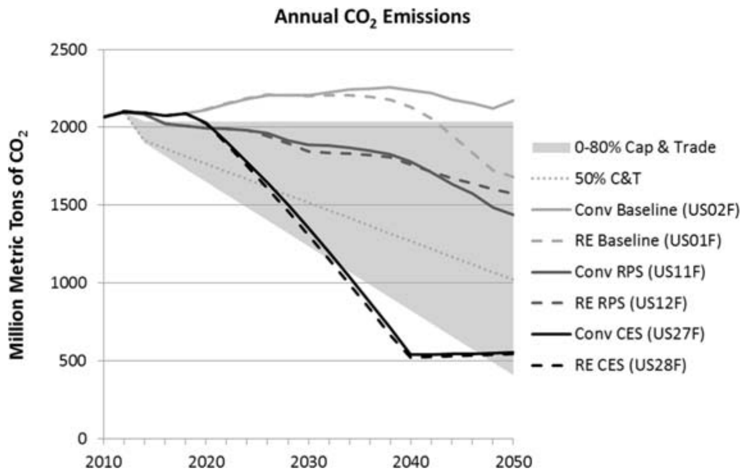


Table 2: Policy Comparisons of Cost and CO_2 Emissions

	Present Value System Cost Increase from Baseline	Cumulative CO_2 Emissions Reduction from Baseline	Present Value CO_2 Emissions Reduction from Baseline	Average cost of abated CO_2 ($/ton)
Baseline	—	—	—	—
50% Cap & Trade	3–8%	27–30%	22–23%	23–56
80% Cap & Trade	7–14%	40–43%	31–32%	38–72
RPS (50%)	−0.1–0.04%	10–14%	9–10%	−16–8
CES (90%)	5–12%	37–39%	25%	36–78

Notes: All figures are for 2012–2050 time period; average cost of CO_2 is on a present-value basis. Ranges are over technology options (RE & Conv).

The RPS and CES policy options represent concepts that have, in recent years, been considered more politically tenable in the United States than a cap and trade system (Broder 2010). The set of scenarios in this analysis project allows us to compare the effectiveness of those alternative policies at reducing CO_2 emissions to each other and to the cap & trade policies. Acknowledging that there are metrics other than cost of CO_2 mitigation that are relevant to selecting an appropriate policy option, we will limit ourselves to that metric in this paper. In Table 2, next to estimates of system-cost- and emissions changes for a subset of the analyzed scenarios, are listed estimated costs for carbon abatement. The cost figure is on a present-value basis (present-value of emission reductions to 2050 divided-by present-value system cost to 2050), and the ranges—as for the other columns in the table—reflect the different technology-assumption scenarios (RE and Conv) under consideration.

The RPS policy has the lowest average cost of abatement of the four highlighted mitigation policies, but also has the lowest reductions, on par with a 20% cap & trade scenario. The negative end of the RPS abatement cost range reflects that the RE-RPS scenario has a slightly-lower present-value system cost than the RE-baseline scenario. While counterintuitive, this can be explained by invoking shortsightedness: if a policy shifts expenditures from fuel to capital investments in the short term, it can reduce long-term costs if those capital investments reduce future need for fuel, even if the present expenses are higher. Because of ReEDS' sequential-solve formulation, it has no foresight of future changes, and thus is susceptible to a myopia similar to that of many real-world investment decisions. In the RE-RPS scenario, the RPS redirects expenditures to more-productive long-term use, reducing long-term costs compared to the baseline.

There is an interesting dichotomy between carbon prices in the 50% and 80% cap & trade pathways. While the carbon prices in the 50% cap scenarios follow a trajectory of steady increases from year to year, the 80% scenarios spike in later years—2040 with the Conv prices, 2044 with RE prices. The spike in carbon prices corresponds to the year that non-sequestered coal is driven out of the generating mix: without coal-gas fuel-switching as a mitigation option, carbon prices rise. These higher carbon prices do, however, allow nuclear and CCS options to be competitive in late years of the Conv scenario.

The CES policy produces cumulative emissions to 2050 almost on par with the 80% cap & trade scenario, but on a more-compressed schedule (Figure 8). The slightly lower present-value emission reduction, paired with the greater cost uncertainty in the CES case compared to the 80% cap, leads to a slightly higher average abatement cost range: \$36–78 compared to \$38-\$72 for the CES.

5. CONCLUSIONS

The set of scenarios explored in this analysis allows us to create a picture of how a selection of policies might affect electric-sector expansion and operation, system costs, and carbon mitigation. The analysis used NREL's ReEDS model, which ensures that investment and dispatch decisions are made in accordance with the constraints and dynamics of the system: ensuring transmission availability, maintaining reliability of power provision, favoring existing infrastructure over new construction. Given the inherent constraints of expanding and using the power system, these scenarios describe how the power system in the United States might develop over the next several decades depending on how policy and technology futures play out.

As with the results of any model, this analysis is circumscribed by the limitations of the ReEDS model. In particular, ReEDS models a firmly-bounded U.S. electric sector: transfers of abatement credits and leakage to other sectors and countries are not included, and end-user response is included only via price-elasticity of demand. Consequently, the costs and relationships discussed here are over a set of scenarios with fairly static system boundaries. Other sectors do not electrify in response to carbon signals, nor do the mitigation options and capabilities of other sectors influence electric sector targets or behaviors. Full representation of the larger economy would likely produce somewhat different results than these electric-sector-only scenarios.

The ensemble of scenarios included in this analysis cover a range of energy policies with different approaches to GHG mitigation: cap and trade programs with different cap levels, renewable energy standards, and clean energy standards. Each of the proposed policies is represented by at least a pair of scenarios with different technology cost assumptions. The dual levers of mitigation policy and technology development arcs show that there exists a range of possible mitigation pathways for a given policy. Lower costs for wind and solar lead, in general, to those technologies being more substantial contributors toward meeting the policy goal (the energy standard or the emission reduction) than when more expensive, though the already-competitive onshore wind technology can see its contribution eroded due to competition from offshore wind and solar technologies.

While this analysis certainly did not include all possible combinations of technology futures, the set of scenarios assembled does demonstrate that if a certain mitigation option is unavailable or expensive, there exist alternative pathways toward meeting the policy goal: in the absence of nuclear and CCS technologies, an 80% reduction in electric sector carbon emissions can still be met with natural gas and renewable technologies without a dramatic increase in cost.

In addition, the analysis shows that renewable resources can be substantial contributors to system adequacy, displacing substantial amounts of thermal capacity. And, far from being regionally-restricted, substantial renewable energy development occurred across all regions of the country. To be sure, in meeting national mitigation goals, each part of the country developed its own mix of generation sources to take best advantage of its endowments and diversity.

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Investigating Technology Options for Climate Policies: Differentiated Roles in ADAGE

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ABSTRACT

This paper examines a range of technological and regulatory approaches to reducing greenhouse gas (GHG) emissions. Availability of new technologies will control how the economy and energy infrastructure respond to any future climate policies. How such policies interact with other types of environmental regulations will also influence the best options for meeting emissions goals. To investigate these effects, the ADAGE model is used to examine policy impacts for several climate and technology scenarios, focusing on key factors such as emissions, technology deployment, energy prices and macroeconomic indicators. In general, the simulations indicate that reductions in GHG emissions can be accomplished with limited economic adjustments, although the impacts depend on both the regulatory approaches used and the future availability of new low-carbon technologies.

Keywords: Climate change, Computable general equilibrium, Electricity, Cap-and-trade, Renewable energy standards, Clean energy standards, Greenhouse gas emissions

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1. INTRODUCTION

Given the lack of progress on establishing a national cap-and-trade system for greenhouse gas (GHG) emissions, interest in the United States has focused on alternative approaches for improving energy systems in the country, especially those related to electricity generation and transportation. The 2011 Economic Report of the President stated that a Clean Energy Standard (CES) for electricity would play an important role in reducing domestic emissions, and many states have already instituted CES or renewable energy standards (RES). Also, in August 2012, President Obama announced new regulations to achieve fuel economy in personal vehicles equal to 54.5 miles per gallon by 2025, with the support of automobile manufacturers. This paper examines how such existing and proposed regulations may interact with more comprehensive cap-and-trade climate policies in the future.

What technology options are available both now and in the future will have significant implications for any adjustments to the U.S. energy infrastructure needed to meet future climate goals in this context. Some technological approaches may be more effective at lowering GHG levels

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than others, and what are the most cost-efficient options under one set of regulations may not work well under another set. As such, this paper examines interactions between a broad cap-and-trade system for GHG allowances and the more industry-specific features of CES and RES. The investigation is conducted under a range of assumptions about technology options and baseline emissions in the absence of any policies.

To focus more explicitly on the role of electricity generation under a setting of RES or CES mandates, the RTI *Applied Dynamic Analysis of the Global Economy* (ADAGE) model, a computable general equilibrium (CGE) model, has been linked to a more detailed linear optimization model of the United States electricity industry. CGE, or "top down," models emphasize interrelationships in the economy and how economic theory can be used to evaluate policy responses in a model with real-world data. However, they tend to lack the technological detail needed to examine some types of legislative proposals, especially those related to renewable electricity generation. On the other hand, "bottom up" technology models can provide much more detailed characterization of generation options, renewable resources, and electricity demand, but lack the ability to look at national policies in a broader context if there are macroeconomic implications to policy features.[1]

This paper attempts to combine the best feature of both classes of models in order to explore the impacts of alternative transition pathways to a future economy with fewer GHG emissions. Several scenarios are run to evaluate the impacts of technological availability on model results. Results of all scenarios are compared against a "business-as-usual" reference forecast to examine effects on emissions levels and the resulting GHG allowance prices, along with economic indicators such as Gross Domestic Product (GDP) and household consumption, and energy prices. The rest of the paper is organized along the following lines: Section 2 first describes the CGE component of the ADAGE model, followed by a description of the electricity model that places a special emphasis on modeling the characteristics of renewable generation, and finally a discussion of how alternative technology assumptions are considered. Section 3 covers the policy settings of interest, and Section 4 gives model results for GHG allowance prices, electricity generation, and other macroeconomic findings.

2. MODEL DESCRIPTION

The RTI ADAGE model is a dynamic, intertemporally optimizing CGE model designed to estimate the macroeconomic effects of climate-change mitigation policies, potentially along with the impacts of climate change itself on the economy. Because many of the most effective options for reducing GHG are anticipated to be in the electricity sector, for this investigation the macroeconomic component of ADAGE has been linked to a detailed dispatch model of U.S. electricity generation options. The electricity model—RTI Electricity Markets Analysis (EMA) Model—has been adapted to focus on choices related to climate policies and also incorporates information on the characteristics and availability of wind and solar generation from the National Renewable Energy Laboratory's (NREL) ReEDS electricity model (Short et al., 2011).

2.1 Macroeconomic Model

The overall structure of ADAGE is similar to other CGE models used to evaluate climate policies such as the MIT EPPA model (Babiker et al., 2008)—see Ross (2009) for more detailed

1. Examples of literature in this area include Hourcade et al. (2006), Böhringer (1998), and Lanz and Rausch (2011).

Table 1: ADAGE Model Components

Sectors and Energy	Factors and Personal Transport
Industries	**Value Added**
Agriculture	Capital
Energy-intensive manufacturing	Labor
Other manufacturing	**Resources**
Services	Land
Transportation	Coal
Final Demand	Crude oil
Households (goods, transport, energy, housing services, leisure time)	Natural gas
	Housing Capital
Government (goods, transport, energy)	**Personal Transport**
	Conventional vehicles (incl. hybrids)
Investment	• existing and new
Energy (non-electric)	Plug-in hybrids
Coal	Electric vehicles
Crude oil	Purchased transportation
Natural gas	
Petroleum	

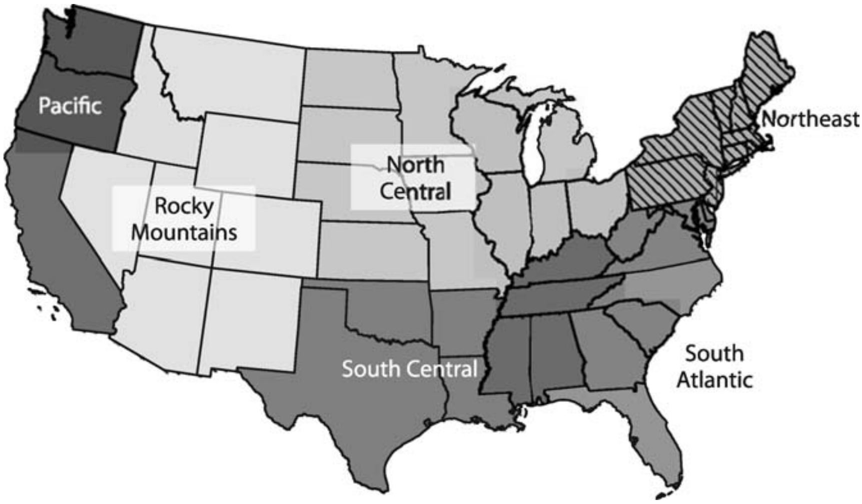
ADAGE model documentation. Economic data in ADAGE come from the IMPLAN and GTAP databases; energy data and various growth forecasts come from the Energy Information Administration (EIA) of the U.S. Department of Energy[2] and the International Energy Agency (IEA). These data are used to describe initial economic and energy market conditions in multiple countries and/or regions to represent the global economy and also the economies of six regions within the United States. ADAGE typically solves in 5-year time intervals from 2010 to 2050 (and beyond) and assumes perfect foresight, where people act to mitigate the impacts of future policies. Emissions and abatement costs for six types of GHG are included in the model—CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.

The sectors of the economy in ADAGE are shown in Table 1. Much of the emphasis of the structure is on the natural resources and industries necessary to provide energy, along with additional detail on how households allocate their purchases across energy and investment goods such as housing and personal vehicles. Other industries are more aggregated in this version of the model. The United States is separated into six regions, aggregated from EIA's Census regions (see Figure 1). The regional breakdown has been chosen to facilitate the linkage to the electricity model discussed in Section 2.2 below.

Features of the ADAGE model with the largest effects on estimated results for climate policies include: the initial energy production and consumption levels (based on IEA and EIA data); growth in economic output and consumption (based on the forecasts discussed below); model parameters that control the ability of households and industries to improve energy efficiency, switch among fuels, and reduce demand (see model documentation); inclusion of emissions and abatement costs for five non-CO_2 GHG (see EPA [2006] for data); representation of new forms of advanced electricity generation—whether nuclear, renewables, or options including carbon capture and storage (CCS)—through a linkage to a detailed electricity model; and, most recently, inclusion of an explicit capital stock in housing that improves the transitional dynamics associated with reducing energy consumption in the residential sector of the economy.

2. This investigation uses EIA's *Annual Energy Outlook 2011* (EIA, 2011a) as the baseline starting point for the model.

Figure 1



Given the importance of energy markets to climate policies, ADAGE distinguishes five primary energy sources: coal, crude oil, electricity (through the detailed model), natural gas, and refined petroleum. In addition to detailed electricity generation options, ADAGE includes advanced types of personal transportation vehicles including plug-in hybrid vehicles and electric vehicles. Other production industries in the model are more aggregated to accommodate computational constraints associated with an intertemporally optimizing CGE framework. The overall structure of the model allows ADAGE to estimate allowance prices associated with meeting GHG emissions targets and consistently evaluate impacts of international climate policies on the United States.

2.2 Electricity Model

The EMA model is an intertemporally optimizing dynamic linear-programming model of U.S. wholesale electricity markets. It is designed to examine how mid- to long-term policies affecting these markets will influence electricity supply decisions, generation costs, and wholesale electricity prices. To accomplish this, the model determines least-cost methods for meeting electricity demand on a seasonal and time-of-day basis, while considering factors such as growth in demand, peak demands, and any limits on emissions or other electricity policy goals.

2.2.1 Structure of the Electricity Model

The basic structure of EMA is similar to other models such as IPM (EPA, 2010), where the objective function of the model attempts to minimize the costs of generating enough electricity to meet exogenous demands. While the linkage to ADAGE requires some modifications to this objective function to facilitate convergence between the two models (see discussion in Section 2.3), the basic structure remains (see Table 2 for details). Annual electricity demands at a regional level (from AEO forecasts) are expressed through load duration curves that convert the annual demand into demands distinguished by season and time of day to reflect the unique, non-storable nature of electricity. The demand side of the model also reflects decisions of generators to maintain adequate reserves over anticipated peak demands to ensure reliability.

Table 2: EMA Model Components

Electricity Demand	Electricity Supply	Electricity Prices and Costs
Annual	**Existing Units**	**Electricity Price (endogenous)**
Forecasts from AEO 2011	Region (13)	Wholesale
Interactions with ADAGE	Types per region (22)	**Existing Unit Costs**
Intra-annual Load Duration Curve	12 fossil by heat rate	Fixed O&M by:
Seasons	10 non-fossil	Type of unit
Summer	**New Units**	Age
Winter	Non-wind Types	Installed equipment
Time of Day	Coal (w/ & w/o CCS)	Variable O&M
Day	Gas CC (w/ & w/o CCS)	**New Unit Costs (from AEO)**
Night	Nuclear	Capital
Morning/evening	Biomass	Fixed O&M
Peak hours (top 1%)	Landfill gas (3)	Variable O&M
Peak Demand (annual absolute)	Geothermal (10)	**Fuel Costs**
Reserve Margins over Peak	Solar (CSP & PV)	Type
Transmission Limits among regions	Wind Types (50) by:	Coal (from ADAGE)
	Region	Natural gas (from ADAGE)
	Wind class	Oil (from ADAGE)
	Cost class	Nuclear (from IPM)
	Resource Constraints	Biomass (supply curve)
	Biomass supplies	Heat rate (Btu per kWh)
	Geothermal	**Emissions**
	Hydro	CO_2 as function of:
	Wind availability	Fuel (coal, natural gas, oil)
	Generation Profiles	Heat rate
	Wind	
	Solar	
	Retirement	
	Min. Generation	
	Coal	
	Steam Oil/Gas	

On the supply side of the model, electricity is generated by either existing units or through construction of new units. The NEEDS database (EPA, 2010) of over 15,000 existing units is aggregated into 256 model plants across regions, types, and heat rates. Information from the IPM model (EPA, 2010) also informs the model regarding units' availability, retirement options, and necessary minimum generation levels. Characteristics of new units are taken from the *Assumptions to AEO 2011* (U.S. EIA, 2011b), including construction and operating costs and fuel efficiencies. More detailed information on wind generation options is discussed in Section 2.2.2.

Generating costs for existing units are from IPM (EPA, 2010) and new units are from EIA (2011b). Fuel costs for uranium and biomass are also from IPM, while ADAGE determines coal, gas, and petroleum prices through the linkage discussed in Section 2.3—starting from the AEO 2011 forecasts for fuel prices faced by the electricity sector. The CO_2 emissions resulting from these fuel choices can be limited through policy instruments, as can goals such as desired levels of renewable generation.

The electricity model is constructed along state lines in order to ensure an adequate convergence with the macroeconomic side of the economy. Figure 2 illustrates how particular parts of the six regions in ADAGE have been further disaggregated to better reflect conditions in electricity markets. Several states are modeled individually to reflect their unique nature, or limited transmission options, with surrounding states—California, Texas, Florida, and New York. Other regions in ADAGE have also been disaggregated to more closely follow feasible options for transmitting

Figure 2

electricity across regional boundaries. When EMA is linked to ADAGE, the resource demands from the more detailed regions in the electricity model are aggregated to match the economic model.

2.2.2 Characteristics of Wind and Solar Generation from NREL's ReEDS Model

In an electric sector capacity expansion model like EMA, it is important to account for distinctive characteristics of wind and solar resources, especially the spatial mismatch between resource and load and the temporal variability and uncertainty of output. EMA takes several steps to include such characteristics in making its investment decisions: resource supply curves, cost consideration for accessibility, contribution toward firm capacity, and value of energy produced.

Wind and solar resource supply curves, represented as MW of available resource in a given wind power class in each region are derived from the resource supply curves used in NREL's Regional Energy Deployment System (ReEDS) model. The wind resource supply curves are expanded in a second dimension to account for the relative accessibility of the resource. Potential wind sites that are close to loads or existing transmission lines with available capacity are less expensive to develop than remote sites. The accessibility supply curve, which manifests as additional investment cost, is calculated for ReEDS via a geographic information system optimization described in the appendix of the ReEDS documentation (Short et al., 2011). Wind resource in EMA, then, is characterized by MW of potential resource of a given quality—defined by annual average capacity factor—and accessibility—distance to access a load or line. Thus far, solar resource is characterized by resource quality only.

Variability and uncertainty of plant output also affect the economics of renewable energy investment, and those impacts tend to grow with increasing penetration of variable renewable resources. Major factors that influence the value of a renewable investment are its impact on reliability and the value of the energy it provides. For reliability, EMA has capital requirements: firm capacity from generating units must exceed expected peak loads by a reserve margin. Wind and solar contribute fractionally—a measure called capacity value (CV), based on statistical output at times of peak load—to this capacity requirement (Milligan and Porter, 2008). With this formulation, each plug of additional capacity of wind or solar in a region receives a lower CV than that previously installed. Because of the linear structure of EMA, wind and solar CV are independent of the other technology's installation level, and regions are also independent of each other. Mitigating the issue of technological and regional independence is that as the CV erodes in a region or for a technology as capacity increases, other regions and technologies look more attractive in comparison, so EMA naturally diversifies its supply.

There are two aspects of EMA that together account for the value of energy provided by wind and solar installations. The ten seasonal and diurnal time slices in EMA value energy provided during peak load times more highly than that provided during off-peak times, and the model's defined seasonal and diurnal capacity factors for wind and solar inform what and where to build. To account for those times when supply exceeds demand due to high renewable output and low load, EMA also includes estimates of surplus energy as a function of penetration level (Ela, 2009). As more renewable capacity is installed, additional capacity has associated with it higher curtailment levels, which reduce the energy it contributes toward meeting load and, consequently, its value. As with the CV supply curves, the curtailment supply curves are independent across technologies and regions.

Together, the resource quality, accessibility, capacity value, and curtailment supply curves shape how EMA values wind and solar installations. Higher quality resource and more accessible sites are more valuable and less expensive, but increasing installations erode the value of all new construction through lower CV and higher curtailments.

2.3 Links between ADAGE and EMA

National cap-and-trade policies and associated allowance prices influence fuel markets and labor/capital costs. To simulate the effects in each policy scenario, ADAGE first determines economy-wide demand for electricity, fossil fuel prices, and other resources used in electricity generation. Next, the EMA electricity model determines the most efficient generation options to meet demand and the associated demands for fuel and other resources (e.g., capital and labor). The results from EMA are then sent back to ADAGE. The iterative process continues between the two models until their solutions converge.

To implement the iterative procedure, we use techniques developed in Böhringer and Rutherford (2009), the "top-down" ADAGE macroeconomic model is linked in an iterative fashion to the "bottom-up" EMA electricity generation model. The decomposition algorithm that maximizes total surplus in the electricity markets (producer and consumer surplus). The process involves expressing electricity demands in the electricity model through a non-linear demand curve, rather than through a fixed demand as in some versions of models such as IPM (EPA, 2010). The EMA model is then solved as a quadratically constrained program using demand elasticities from ADAGE to speed convergence between the two models (see Rausch and Mowers [2012] and Lanz and Rausch [2011] for details of this type of process).

2.4 Modifying Technology Assumptions within ADAGE and EMA

ADAGE and EMA models were adjusted to be consistent with the technology assumptions for the EMF study. We describe the adjustments below:

- *End Use Technology*—**low** versus **high**: ADAGE normally uses autonomous energy efficiency improvements (AEEI) to match AEO forecasts through 2035. These declines in energy use are assumed to be offset by additional use of capital to pay for the efficiency improvements, leading to lower energy and higher capital requirements per unit of output in production after the initial model year of 2010. After 2035, economic growth is determined by population growth forecasts from the U.S. Census Bureau, combined with improvements in labor productivity from the terminal years of the AEO forecasts. The level of economic growth is then combined with trends in energy efficiency improvements in the final years of the AEO forecasts to give total energy use after 2035. This approach is assumed to represent the **low** end-use technology case. For the **high** end-use technology case, the energy inputs to production and final demand are lowered such that final energy consumption is 20% lower in 2050 than in the **low** case (no adjustments are made to electricity generation options). These adjustments in energy are not offset by additional capital requirements to represent absolute improvements in efficiency, which gives slightly different baselines for the two cases. Note: this represents a substantial reduction in energy demand, leading to a decline in electricity demand over time, for example.

- *Carbon Capture and Storage (CCS)*—**low** versus **high**: In the **low** case, CCS is unavailable. In the **high** case, new CCS units (natural gas combined cycle and integrated coal gasification combined cycle) are available with costs and characteristics based on EIA (2011b). No improvements in capital costs or heat rates are assumed beyond 2035. Upper bounds on the ability of utilities to construct **CCS** and/or nuclear units from the IPM model (EPA, 2010) are applied in the **high** case.
- *Nuclear Energy*—**low** versus **high**: In the **low** case, nuclear is phased out with no new construction of nuclear units beyond those already planned or under construction. Existing units are retired at the end of their 60 planned lifetimes, based on data from the IPM model (EPA, 2010). In the **high** case, new nuclear units are allowed with costs and characteristics from EIA (2011b). No improvements in capital costs or heat rates are assumed beyond 2035. Upper bounds on the ability of utilities to construct CCS and/or **nuclear** units from the IPM model (EPA, 2010) are applied in the **high** case. Note: regardless of availability, no new nuclear is constructed in the EMF baseline cases due to their construction and operating costs compared with other generation options.
- *Wind and Solar Energy*—**low** versus **high**: In **the** low case, costs and availability of wind and solar generation are those discussed in Section 2.2.2. In the **high** case, availability of wind and solar resources is unchanged. Wind capital costs are lowered by 10% and solar capital costs are lowered by 35%—roughly based on information used by NREL from Black and Veatch.
- *Biomass Energy*—**low** versus **high**: In the **low** case, biomass costs and availability for electricity generation are based on the IPM model (EPA, 2010). In the **high** case, biomass prices are lowered by 25% and supplies are increased by 25%.

2.5 Additional Technology Options

ADAGE has historically considered technology options and associated costs for improving energy efficiency. To do this, ADAGE adopted methods for specific individual technologies (including advanced types of electricity generation) using approaches discussed in Jacoby et al. (2006) and Böhringer and Rutherford (2008). However, the current version of ADAGE now considers advanced electricity generation technology and efficiency choices within the detailed electricity sector model. In addition, the current version of ADAGE also includes advanced technology options for personal vehicles. The model distinguishes between purchased transportation services (e.g., air and bus travel) and investments for self-provided transportation (i.e., personal vehicles). For conventional vehicles, ADAGE follows Paltsev et al. (2005) and allows households to choose to invest more in new vehicles to improve miles per gallon (existing personal vehicles have fixed MPG). For unconventional vehicles such as plug-in hybrids and electric vehicles, ADAGE considers characteristics associated with the advanced options such as gasoline and electricity needs, the cost of substitute conventional vehicles, and the rate at which such new advanced vehicles are likely to enter the market (see Karplus, Paltsev, and Reilly [2010]).

3. SCENARIO DESCRIPTIONS

The methods for implementing specific features of the EMF scenarios are discussed below. Any methods used that may be unique to the ADAGE modeling structure are covered here.

3.1 Primary Baseline (US02)

The US02 baseline is calibrated to the GDP growth, energy use, and policies in the AEO 2011. The one important exception is that the baseline assumes final energy consumption is 20% lower by 2050 than the model would normally project from an AEO forecast. The US02 baseline is identical to the US01 baseline because CCS and nuclear do not enter in the absence of a climate policy as growth in baseline electricity demand and impacts of nuclear retirements are offset by cheap natural gas generation. Similarly, additional wind, solar, and biomass do not enter the baseline as the model does not currently force compliance with federal, state and regional policies and subsidies related to renewables, which will lead to costs for climate policies being overestimated. The US02 baseline and policy scenarios listed below, except where noted, also have the following features:

- High end use technology
- High CCS and nuclear
- Low wind/solar and biomass

3.2 Policies

Our study considers several policy cases. The US04 (50% cap-and-trade) represents a national policy to reduce cumulative greenhouse gas emissions between 2012 and 2050. A linear reduction from 2012 levels reaches 50% below 2005 levels by 2050, covering all Kyoto gases from all sectors of the economy, with the exception of CO_2 emissions from land use and land use change.

US06 (RPS, CAFE):[3] The renewable portfolio standard (RPS) applies to the electricity sector and includes hydroelectric and biomass generation, along with the other renewable sources. It mandates 20% renewables by 2020, 30% by 2030, 40% by 2040, and 50% by 2050. Banking and borrowing of RPS allowances over time is not allowed. The CAFE standard for new personal light-duty vehicles (LDV) calls for a linear increase in fuel efficiency, starting in 2012 and reaching a level by 2050 of three times what it was in 2005. This fleet-wide standard applies only to new

3. The EMF case also specifies all new coal plant capture and store 90 + % of their CO_2 emissions. No new coal without CCS is constructed in these cases so this condition is met in all scenarios.

vehicles in the model and includes the benefits to overall new LDV fuel economy of any new plug-in hybrids or electric vehicles.

US28 (CES): Similar to US12, this scenario is a clean energy standard (CES) applied only to electricity generation. In addition to the sources covered by the RPS, it includes nuclear power, fossil CCS (credited at 90%), and natural gas (credited at 50%). Targets for generation from these sources are 50% by 2020, 60% by 2025, 70% by 2030, 80% by 2035, 90% by 2040, and constant thereafter (the current share of "clean electricity" in the U.S., as defined here, is 42.5%). Banking and borrowing of CES allowances over time is not allowed.

3.2.1 Variations of (50% cap-and-trade)

The US03 (50% cap-and-trade) is similar to US04 but assumes that CCS and new nuclear *are not* available. In addition, renewables are less expensive and biomass more abundant. (Note that since the baselines US01 and US02 are identical, the US03 and US04 policy cases begin from the same starting levels of economic growth and emissions).

US08 (50% cap-and-trade, RPS, CAFE): This scenario combines the requirements of US04 and US06 to examine any economic efficiency losses caused by the RPS and CAFE goals.

US21 (baseline) and *US22* (50% cap-and-trade): This baseline and associated cap-and-trade policy are similar to scenarios US02 and US04, respectively. The exception is that this baseline and policy case are based on the low end use technology assumption, thus final energy demand in 2050 is 20% higher in US21 than in US02. Higher baseline energy use has important implications for costs and technologies associated with achieving a 50% reduction in emissions.

US23 (baseline) and *US24* (50% cap-and-trade): This baseline and policy case represent the most restrictive set of assumptions about baseline energy demands and the technologies that might be available to meet a cap-and-trade target in the future. It combines the more conservative, low end use technology assumption of US21 with the assumption that no new CCS or nuclear generation will be available, along with more expensive sources of renewable electricity.

4. RESULTS

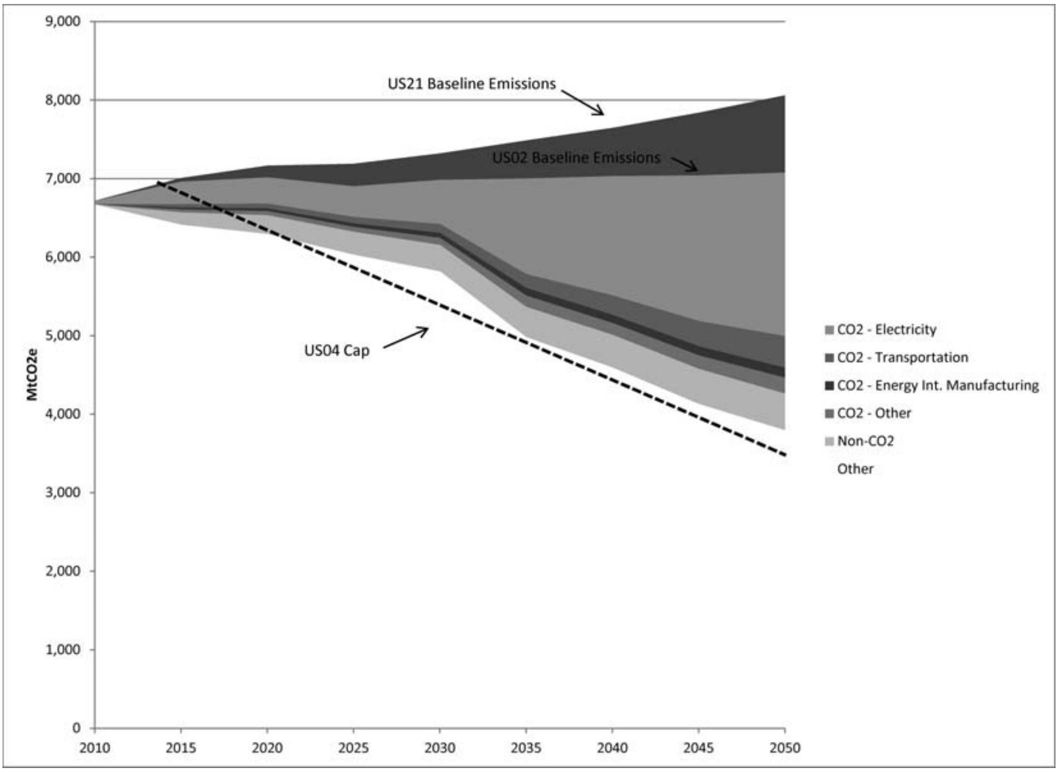
This section first discusses model results for emissions and allowance prices. It then focuses on electricity generation, which is an important source of both emissions and reduction opportunities, and the macroeconomic results, before exploring in wind and solar generation in more detail.

4.1 Overview of GHG Emissions and Sources of Abatement under US04 (50% cap-and-trade)

Under high growth in end use technologies (US02 baseline) there is little growth in baseline emissions versus the end use baseline (US21 baseline). As a result, U.S. industries will find it easier to meet emission targets under the 50% cap which is represented by the dashed line in Figure 3. During the early years of the policy, emissions are slightly below the cap as an emissions bank is accumulated. During the later years, the bank is drawn down although emissions in this case tend to follow the cap relatively closely.

The electricity sector is expected to be an important and cost-effective source of emissions reductions. In 2025, the electricity sector contributes 45% of abatement and grows to over 60% by 2050. Abatement is driven by a significant shift in the generation mix from coal-fired to natural gas-fired electricity. The sector finds it economical to make the switch because it anticipates natural

Figure 3



gas will be cheaper in the future, some CCS units will be constructed, and electricity demand eases as a result of energy efficiency improvements.

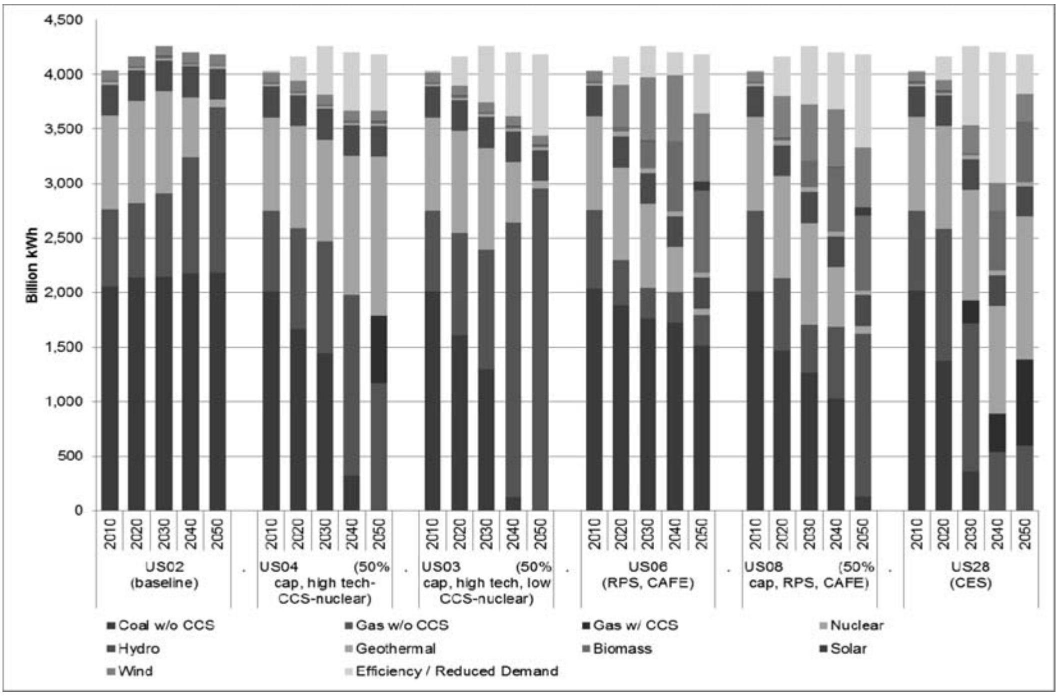
Other sectors of the economy with low-cost abatement option also are an important source of reductions. For example, a significant CO_2 emissions source, transportation, represents approximately one third of CO_2 emissions and contributes around 10% of total abatement in response to modest price signal associated with higher petroleum prices. Petroleum prices increase around \$0.20 per gallon in 2025, rising to roughly \$0.70 per gallon by 2050.

4.2 Comparing and Contrasting Electricity Sector Abatement Under Different Policies

The electricity sector provides a large share of total emissions abatement under all scenarios. However, the way in which the generation mix evolves over time is influenced by what technologies are available and the additional goals above a cap-and-trade system that are imposed. Today, approximately 70% of U.S. electricity is provided by fossil fuels, with a large share that coming from coal. In the absence of climate policies, the fossil share is expected to increase over time. As shown in US02, the model projects that, due to low natural gas prices, the expected retirement of nuclear units will largely be offset by an increase in natural gas generation. Note that baseline electricity demand remains relatively stable as the result of the assumption of high improvements in end use technologies. Figure 4 illustrates generation in the US02 baseline case and contrasts it to several cap-and-trade and other scenarios.[4]

4. The graph in Figure 4 ignores a small amount of generation provided by existing petroleum-fired units in the model, does not include a category for coal IGCC + CCS generation that is not active in any of the scenarios, and aggregates

Figure 4



4.2.1 50% Emissions Cap Only

To meet the 50% emissions cap, the most cost effective methods are new nuclear and low-cost natural gas units, some of which include CCS. There is little change in renewables given the availability of inexpensive natural gas. Towards the later years, the constraint in the electricity model that limits the combination of new nuclear and CCS prevents gas CCS from being selected until 2045. All existing coal is retired by 2050. The later years also have a demand reduction of around 10% due to efficiency improvements and lower demand from higher electricity prices which serve to limit the need for additional renewable generation to reach the emissions goals. The relatively significant reliance on nuclear energy in Scenario US04 is not allowed in Scenario US03. Under the nuclear energy constraint, the emissions cap is met with natural gas (without CCS) and electricity demand reductions approaching 18% by 2050.

4.2.2 Adding Renewable Portfolio Standards

Impacts of a policy goal encouraging renewables are illustrated by the US06 scenario. Here, renewables must reach 50% of total generation by 2050. Contrasting US06 with the US02 baseline, several differences are apparent. While new natural gas forms the main approach to offsetting nuclear retirements in US02, the RPS shifts this emphasis to renewables. Generation by

together wind generation from onshore and offshore sources, as well as solar CSP and PV units. New hydroelectric power is not allowed in any scenario.

non-fossil sources is split relatively evenly between biomass and wind generation, with a small amount of new solar in the later years and an even smaller amount of new geothermal electricity. Existing coal units are largely unaffected by the RPS, but their slight decline and the RPS preventing the need for new gas generators leads to emissions from electricity generation that are more than 40% below baseline levels by 2050.

The reduction in emissions from the RPS in US06, setting aside whether or not this is a cost-effective method of achieving those reductions, leaves comparatively few additional reductions needed from the electricity sector when Scenario US08 adds the economy-wide emissions cap back into the mix. Adding the 50% cap has little additional effect on renewables, but does encourage additional shifting from existing coal units into new natural gas, in addition to a slightly larger drop in demand.

4.2.3 Adding Clean Energy Standards

As specified, the Clean Energy Standard in US28, with its requirement for a 90% CES by 2040, actually leads to the largest cumulative emissions reduction from electricity of any of these scenarios. Coal is completely retired by 2040. Natural gas plays a smaller role than any of the previous scenarios with emissions caps, although this is accomplished through construction of gas CCS to take advantage of the CES credit for this type of generation, even though there is no climate policy in place. The increase in the CES requirement to 90% in 2040, combined with limits on how much new nuclear and CCS can be constructed by 2040 (from EPA, 2010) cause a dramatic drop in demand and generation in that year from an 85% increase in electricity prices. Were it possible to build additional CES generators by this year, such a spike could be avoided. As it stands, given the short-term nature of the spike, it is not cost effective in the model to build new renewable generation in the short run merely to avoid this temporary anomaly.

4.3 Allowances Prices

In the cap-and-trade scenarios, GHG allowance prices reflect costs of abating emissions to meet a given emissions target. In the absence of banking allowances, these prices would equal the marginal cost of removing the last ton of emissions required to meet an emissions cap in each year. Banking can increase allowance prices in the early years of a policy as people exceed emission targets by saving allowances for later years. The flexibility provided by banking does reduce policy costs over time by allowing the most cost-effective reductions to be made at the most cost-effective time. In all cap-and-trade scenarios consider, banking leads to a GHG allowance price path that rises over time with the real, long-term interest rate (assumed to be 5%).

In the RPS/CAFE and CES scenarios, the generation targets also imply allowance prices for RPS/CES credits. The allowance prices reflect the marginal cost of providing the last kilowatt hour of electricity from the renewable, or clean, sources. In contrast with the cap-and-trade scenarios, the RPS and CES scenarios do not allow banking of the RPS/CES credits; as a result their allowance prices will not rise steadily over time.

4.3.1 Allowance Prices under Cap-and-Trade (US04)

As shown in Table 3a, The US04 scenario has a starting GHG allowance price of $14 per MtCO2e, increasing to $81 by 2050. The price reflects the low baseline emissions US02 baseline

Table 3a: Allowance Prices for Cap-and-Trade, RPS/CAFE, and CES

Prices	Scenario	2015	2020	2025	2030	2035	2040	2045	2050
GHG Allowance ($ per MTCO2e)	US04 (50% cap-and-trade, high end use tech)	$14	$18	$23	$30	$38	$49	$63	$81
	US08 (50% cap-and-trade, RPS/CAFE)	$8	$10	$13	$16	$21	$27	$35	$45
RPS Allowance ($ per MWh)	US06 (RPS/CAFE)		$131	$62	$94	$59	$79	$65	$111
	US08 (50% cap-and-trade, RPS/CAFE)		$108	$50	$77	$38	$48	$37	$62
CES Allowance ($ per MWh)	US28 (CES)		$44	$75	$88	$66	$262	$140	$68

result from high end use technology growth and the availability of nuclear and CCS generation to help meet the cap.

4.3.2 Allowance Prices under RPS/CAFE and CES

Allowance prices for RPS credits, necessary for generators to produce a megawatt hour of non-renewable electricity, reflect a relatively high marginal cost of meeting the RPS goals. Comparing US06 with US08 demonstrates how imposing an economy-wide GHG emissions cap reduces the pressure of meeting the RPS targets by encouraging additional switching away from fossil generation. Initial RPS allowance prices are high as the electric sector adjusts its generation mix, and also rise in those years when the renewable targets are raised. For the CES credits, the allowance price shows its most dramatic rise during 2040, when the clean energy target reaches its maximum level, as discussed in Section 4.3.

4.3.3 Allowance Prices under Combined Cap-and-Trade and RPS/CAFE

Scenario US08 represents an interesting study in the effects of combining multiple policy goals simultaneously. Although all of the technology assumptions are equivalent between US04 and US08, the allowance price in US08 is 44% lower than in US04. The decline shows how layering a RPS and CAFE standard on top of a cap-and-trade policy can reduce the apparent marginal costs of meeting an emissions target. However, total costs to the economy of achieving an equivalent level of emissions through multiple policy goals are higher than if emissions are reduced through the more cost-effective, comprehensive economy-wide emissions cap of the US04 scenario (see section 4.4 Macroeconomic effects).

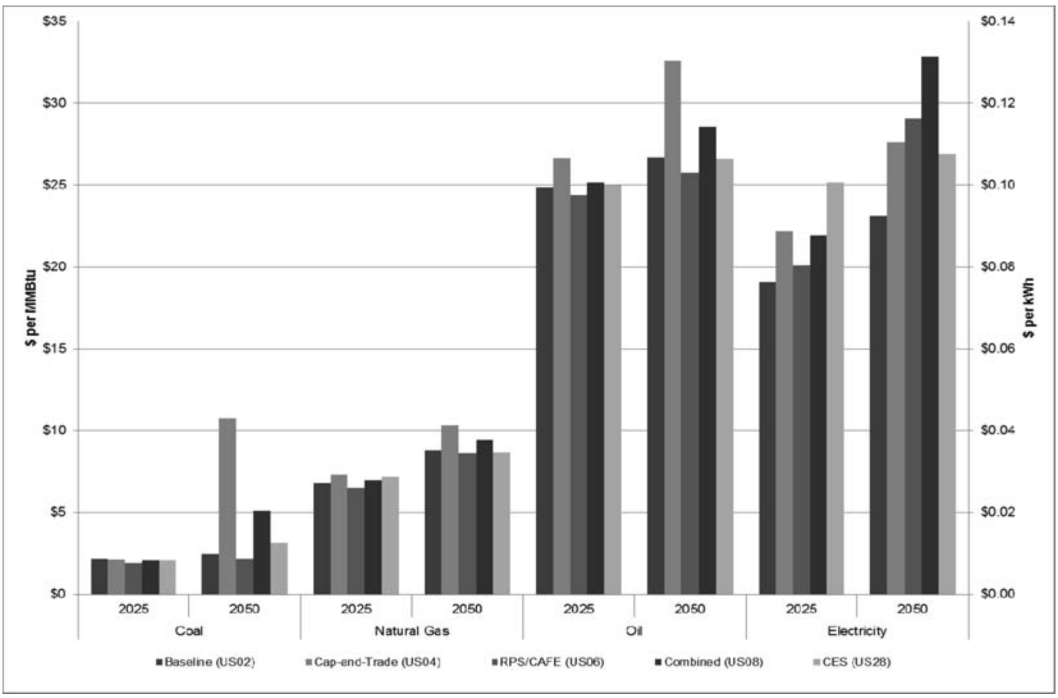
4.3.4 Variation in Allowance Prices under Different Future Technology Options

Across the range of scenarios with a 50% cap-and-trade approach, the allowance prices for US04, US03, US22, and US24 cover comparable policies with different assumptions about future technology options (Table 3b). Scenario US24 begins from the higher baseline emissions shown for US21 in the figure above. It also does not allow new nuclear to be built and assumes that CCS is also not a viable option. These factors increase the GHG allowance price by 75% over US04. Much of this increase is due to the assumption of low end use technology growth, which raises the allowance price more than 56% by itself (US22 versus US04). The remaining increase

Table 3a: Allowance Prices for Cap-and-Trade by Alternative Technology Assumptions

Prices	Scenario	2015	2020	2025	2030	2035	2040	2045	2050
GHG Allowance ($ per MTCO2e)	US04 (50% cap-and-trade, high end use tech)	$14	$18	$23	$30	$38	$49	$63	$81
	US03 (50% cap-and-trade, low CCS/nuclear)	$17	$22	$28	$36	$46	$60	$77	$98
	US22 (50% cap-and-trade, low end use tech)	$22	$28	$36	$46	$59	$75	$96	$123
	US24 (50% cap-and-trade, all low assumption)	$24	$31	$40	$51	$66	$84	$108	$138

Figure 5



in the 2015 allowance price between $22 for US22 and $24 for US24 is the result of restricting nuclear and CCS.

4.4 Delivered Energy Prices

Electricity prices are higher by one to two cents per kWh in 2025 across all the scenarios and two to four cents by 2050 (see Figure 5). In 2050, the electricity price increase is: cap-and-trade (US04)—19%, RPS/CAFE (US06)—26%, and CES scenario (US28)—16%. The scenario that combines the cap, RPS/CAFE, and CES (US08) has largest price increase—42%.

The cap-and-trade results assume allowance costs can be partially passed on to consumers (as is the case in a full auction). If allowances were given directly to electricity producers, the costs of those allowances would not be passed on to consumers in regulated electricity markets. As a result, electricity price increases associated with cap-and-trade scenarios would be smaller than shown in many parts of the United States.

Under the emissions cap policies, the changes in allowance prices cause the natural gas price to rise. Natural gas prices are 18% higher in US04, and 8% higher in US08, than in the US02 baseline scenario due to the GHG allowance prices. In contrast, the RPS and CES only policies result in declines in natural gas generation and lower natural gas prices. Average petroleum prices have similar percentage changes to natural gas prices.

4.5 Macroeconomic Effects

The allowance prices encourage increases in renewable/clean energy and reductions in GHG emissions through fuel switching, investments in energy efficiency and new technologies, and reductions in demand. Although energy markets are an essential component of the U.S. economy, they represent a small share of total domestic output. In addition, use of economy-wide cap-and-trade policies allows producers and consumers to undertake what are, in most circumstances, cost-effective emissions reduction options.[5] These factors help limit any broader macroeconomic effects of such policies, if undertaken through efficient policy instruments.[6] Use of multiple instruments to achieve different goals simultaneously can alter these relationships and move the economy away from the least-cost outcomes.

4.5.1 GDP Changes

As shown in Figure 6, in the US02 baseline, GDP is projected to increase from $13 trillion in 2010 to $22 trillion (65%) in 2030 and to $35 trillion (158%) by 2050.

In 2030, GDP projections and percent differences from the baseline scenario are:

- Baseline: $22.1 trillion
  - Cap-and-Trade (US04): −0.5%
  - RPS/CAFÉ (US06): −1.0%)
  - CES(US28): −0.7%)
  - Combined(US08): −1.3%)

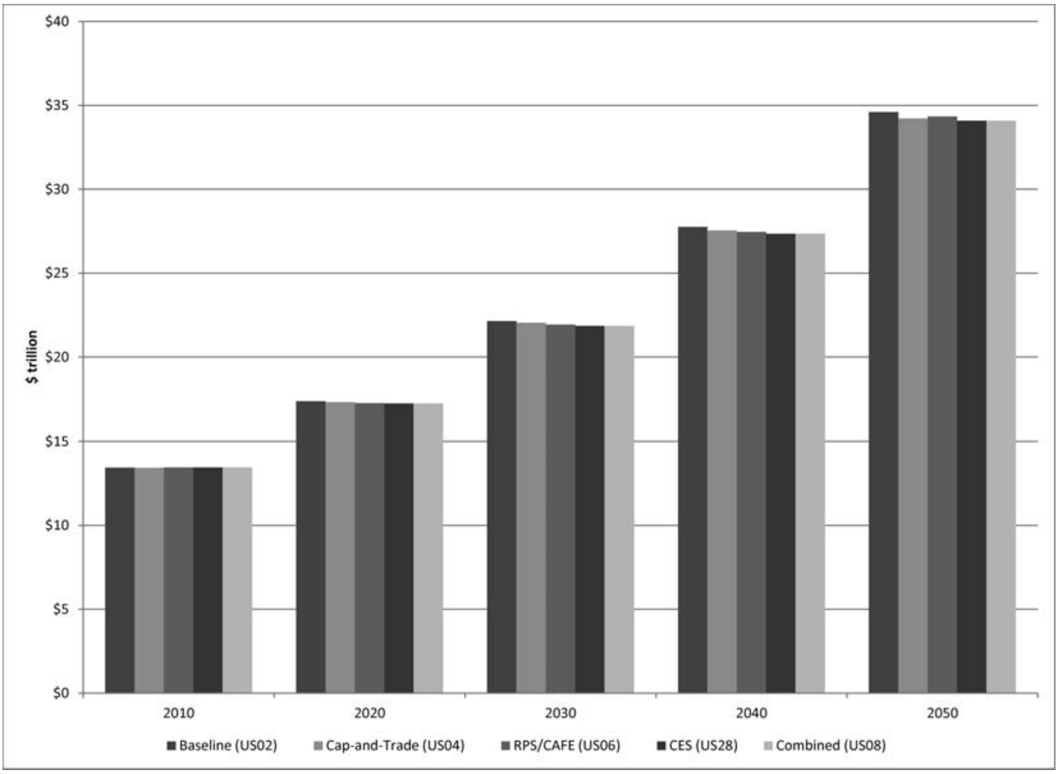
By 2050, projections of GDP and differences from the baseline scenario are:

- Baseline: $34.6 trillion
  - Cap-and-Trade (US04): −1.1%
  - RPS/CAFÉ (US06): −0.8%

5. As has been discussed in the tax interaction literature (see, for example, Bovenberg and Goulder [1996], and Parry and Bento [2000]), the presence of existing tax distortions in the economy can alter the impacts of environmental policies and may allow additional "double dividend" benefits to be achieved if revenues from a cap-and-trade program are used to reduce pre-existing tax distortions. These benefits are not included in the macroeconomic results here as lump-sum distribution of revenues is assumed in this analysis.

6. Note that, given the typical CGE modeling assumption that economies are operating efficiently prior to instituting new policies—aside from the presence of taxes that distort behavior, any adjustments in energy markets will lead to some estimated declines in economic activity as production technologies and consumption patterns are altered.

Figure 6



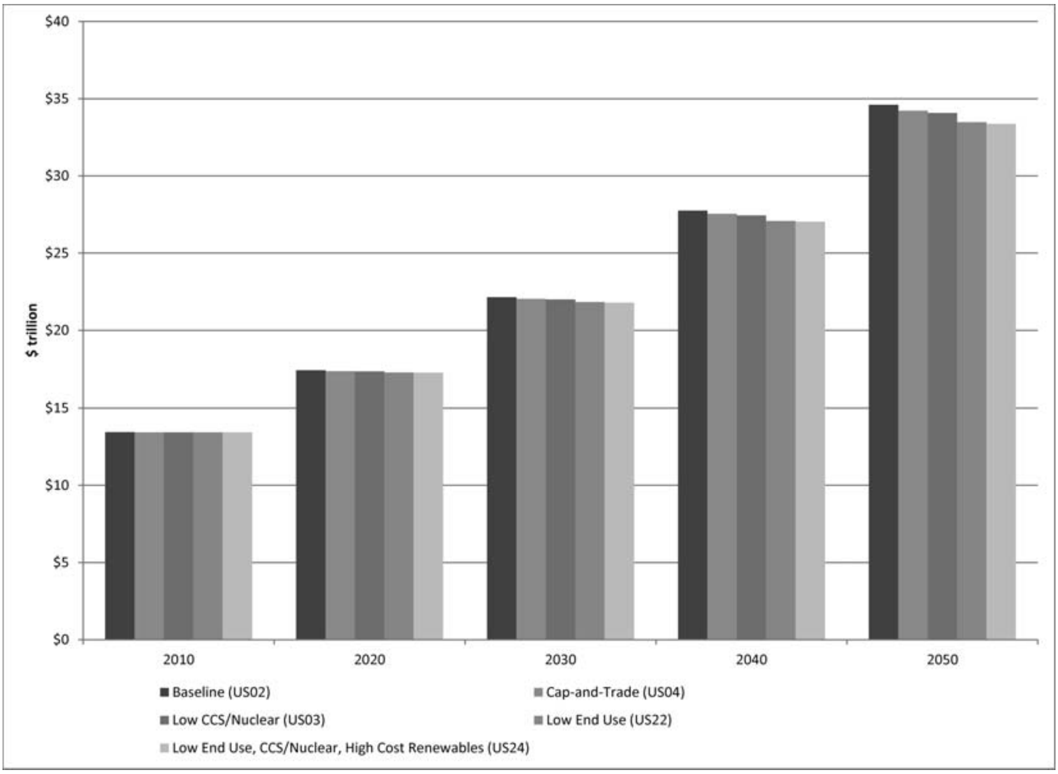
– CES (US28): −0.3%
– Combined (US08): −1.5%

Differences in total estimated GDP tend to expand over time across the policy scenarios, depending on how many policy goals are being pursued in a particular scenario, with the most notable example being the US08 scenario that simultaneously includes an emissions cap, RPS electricity policy, and CES policy. In this particular scenario, even though cumulative GHG emissions reductions are identical between it and US04, the macroeconomic impacts of reaching the same emissions goal are higher due to the RPS and CES standards. While these approaches can have benefits beyond merely reducing GHG emissions, they are not as cost-effective as a cap-and-trade system. Figure 6 compares the Cap-and-Trade (US04) by technology scenarios.

4.5.2 Changes in GDP and Consumption Growth Rates

To facilitate comparisons across scenarios, Figures 8 and 9 present GDP findings, and the related ones for household consumption, in terms of annual average growth rates over a 40 year horizon. In the baseline scenario (US02), GDP is forecasted to grow at an average rate of 2.39%. Growth rates fall by less than 0.05% under all policy scenarios. Under the cap-and-trade (US04) growth falls 0.03%. GDP reductions for the RPS/CAFE scenario (US06) are similar, although GHG emissions reductions from the RPS/CAFE policy are roughly one-half of the cap-and-trade scenario. In the baseline scenario (US02), consumption is forecasted to grow at an average rate of 2.52%.

Figure 7



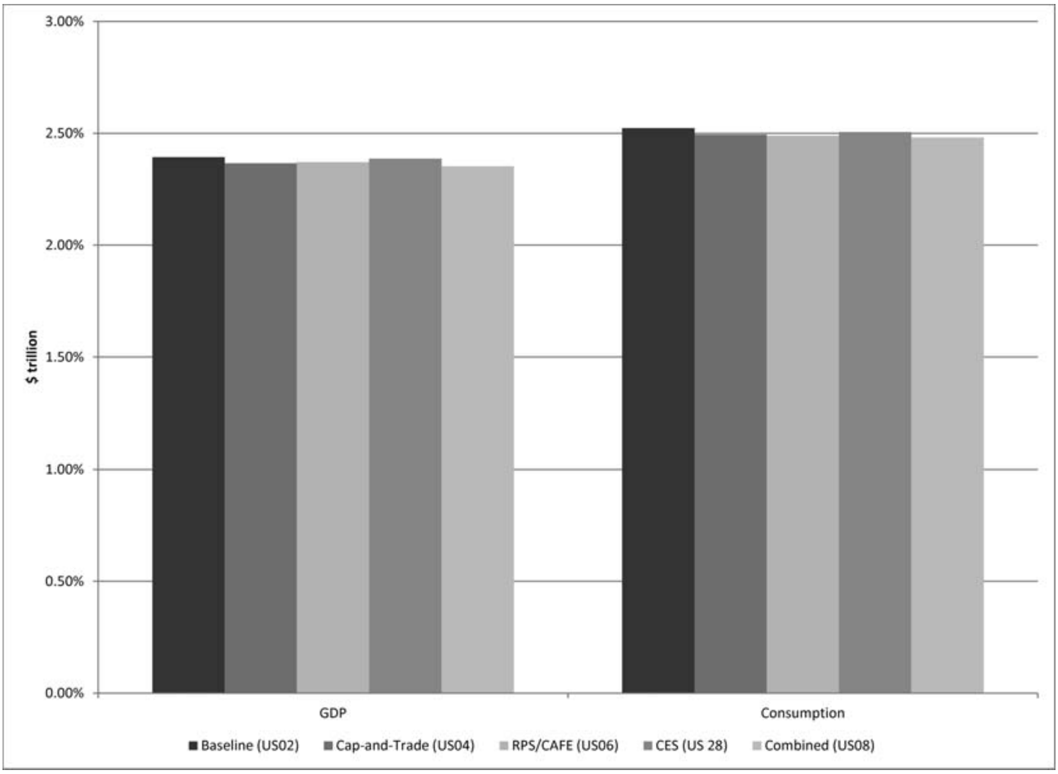
Growth rates also fall by less than 0.05% under all policy scenarios. Under the cap-and-trade (US04) growth falls 0.03%. Figure 9 compares the Cap-and-Trade (US04) by technology scenarios.

4.6 Effects of Modeling Characteristics of Wind and Solar Resources

As discussed in Section 2.2.2, the electricity dispatch model (EMA) incorporates information from the NREL ReEDS model on several distinctive characteristics of wind and solar generation including: resource-quality supply curves, cost consideration for accessibility, contribution toward firm capacity, and value of energy produced. In this section, the effects on generation of two components of this modeling are considered—capacity value (the extent to which additional wind/solar contribute to meeting reserve margins) and curtailment (the extent to which additional wind/solar generation becomes less useful in meeting overall electricity demands as the share of wind/solar in total generation increases).

Figure 10 illustrates how these adjustments to the representation of wind/solar generation can alter model results about the generation mix. For this case, the RPS policy is run as a stand-alone option (US12 scenario with a 50% renewable share by 2050), either with the information on capacity values and curtailments from the ReEDS model (as was done in all the scenarios discussed above) or without these adjustments. The resource supply curves were maintained in all scenarios. Consideration of the factors that may reduce the effectiveness of wind/solar generation leads to total generation from these sources that is 15% lower than without such features in the model. In

Figure 8



addition, as shown, these differences are magnified during some seasons of the year and times of day in which wind/solar plays a larger role in overall electricity generation.

5. CONCLUSIONS

The scenarios modeled here highlight several key points regarding how domestic policy design, as well as factors such as technology availability, can affect costs associated with reducing GHG to achieve climate-change mitigation goals. They also illustrate that, in general, emissions reductions can be achieved without experiencing significant changes in future economic growth or household consumption. The level of reductions, technology options, and policy interactions, however, will influence the exact degree of adjustments occurring in the economy.

New technologies will have a critical role to play in meeting climate change mitigation goals with low impacts on GDP and consumption. The modeling illustrates that policies such as RES and CES for electricity of the types modeled here can achieve significant reductions in GHG emissions as stand-alone policies. However, it is important to bear in mind when interpreting model results that GHG allowance prices under a combined cap-and-trade and RES/CES policy do not reflect the economic costs of the cap-and-trade system alone. To the extent that electricity-specific policy goals, or other technology standards such as CAFE, result in lower emissions from the regulated sectors, the rest of the economy will have fewer adjustments to make to meet emissions goals. In general, however, the combined policy approach will lead to greater economic adjustments in total than cap-and-trade approaches.

Figure 9

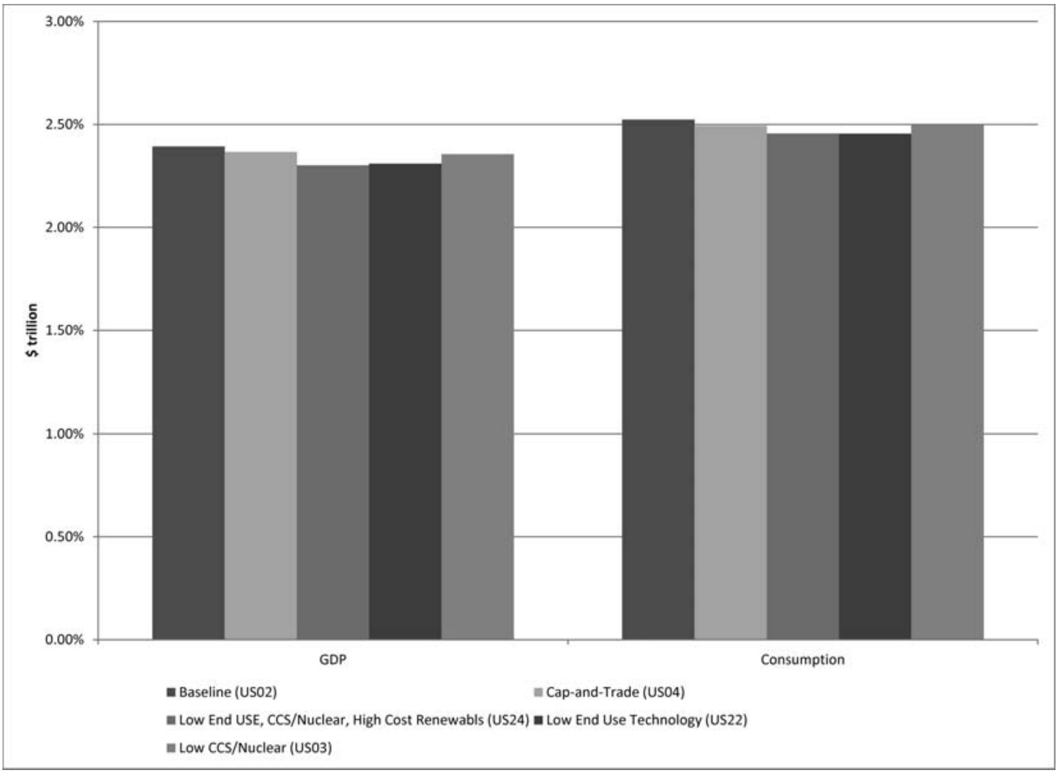


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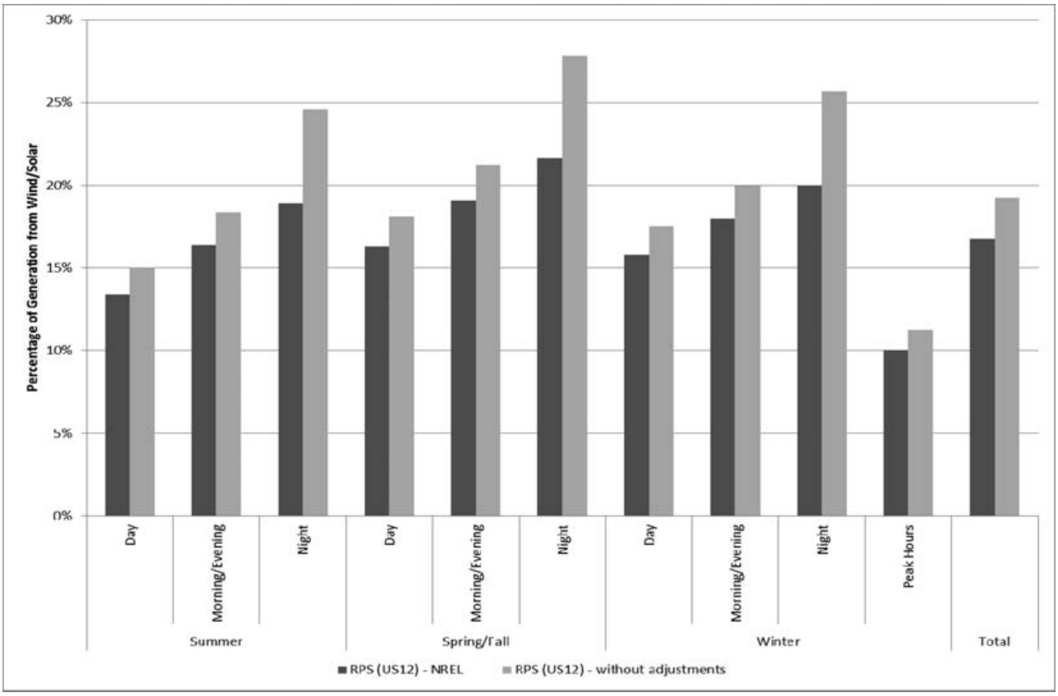
Figure 10



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A Clean Energy Standard Analysis with the US-REGEN Model

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ABSTRACT

A clean energy standard (CES) is a potential policy alternative to reduce carbon emissions in the electric sector. We analyze this policy under a range of technological assumptions, expanding on the Energy Modeling Forum (EMF) 24 study scenarios, using a new modeling tool, US-REGEN. We describe three innovative features of the model: treatment of spatial and temporal variability of renewable resources, cost-of-service electric sector pricing, and explicit representation of energy end-use specific capital.

We find that varying technology assumptions results in vastly different futures, with large contrasts in the distribution and scale of inter-regional financial flows, and in the generation mix. We explore regional differences in how the costs of CES credits are passed through with cost-of-service vs. competitive pricing. Finally, we compare the CES to an economy-wide emissions cap. We find that although the two policies result in a similar generation mix, price and electricity end-use results differ.

Keywords: Clean energy standard, Market-based environmental policy, Greenhouse gas mitigation, Energy modelling, Electricity modeling

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1. INTRODUCTION

Since the defeat in the U.S. Senate in 2010 of the American Clean Energy and Security Act, which included an economy-wide cap on carbon emissions and had been approved by the House of Representatives, the focus of U.S. climate policy has shifted to more regulatory and sectoral approaches. An alternative that appears to be gaining political traction is a Clean Energy Standard (CES) applied to the electric sector. In the 2011 State of the Union Address, President Obama called for 80% of United States electricity to be generated from clean sources by 2035[1,2] a call he reiterated in the 2012 address. Later that year, a CES bill was introduced by the Senate Energy and Natural Resources Committee Chairman Jeff Bingaman, although its prospects for passage remain unclear at the time of writing.

Under a CES policy, a portfolio constraint is enforced on electric generation in which a certain percentage of consumed energy must be generated by qualified sources. The percentage would increase over time, and the definition of qualified sources would be broader than in other similar policies, such as a renewable portfolio standard, possibly including natural gas, nuclear, and

1. Official text of Obama's address available at http://www.gpo.gov/fdsys/pkg/CREC-2011-01-25/pdf/CREC-2011-01-25-pt1-PgH457-6.pdf.

2. http://ase.org/resources/state-union-2011-factsheet-clean-energy-standard-ces.

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coal with carbon capture and storage (CCS). Additionally, qualified sources could be weighted, for example to reflect or approximate the carbon emissions intensity of various generation technologies.[3] The implementation would likely be market-based with a clean energy certificate (or fraction thereof for weights less than one) awarded to qualified generators and a compliance obligation on the part of load-serving entities to acquire certificates equal to the target percentage of delivered energy. A key distinction between a CES and a market-based emissions policy is that no implicit or explicit public sector transfer takes place, e.g. in the form of permit allocation or tax revenue. There is also the potential for large inter-regional transfers as a result of the policy given the geographic diversity of renewable resources.

The idea of a CES is relatively recent. The earliest mention of clean energy credits appears to be in the work of Michel and Nielsen (Electricity Journal, 2008). They proposed trading in *CO2 reduction credits* for electricity generation, arguing that this approach has advantages in terms of administrative and distributional efficiency over the cap and trade alternative. Their paper was descriptive in nature with no analysis to measure the claimed efficiencies. Indeed, to our knowledge, no analytical modeling of the Clean Energy Standard had been conducted prior to its mention in the 2011 State of the Union address. A proposal by Aldy (2011), following the President's endorsement of the approach, argued that a CES "represents a simple, transparent, more cost-effective, and more effective alternative to greenhouse gas regulatory authority under the Clean Air Act and the patchwork of state renewable and alternative energy portfolio standards." [p48] At the state level, Coffman et al. (Energy Policy, 2011) draw some comparisons between a CES and an RPS in the specific case of Hawaii, using a dynamic optimization model of Hawaii's electric sector. They find that a CES policy where the weights on technology are determined by GHG emissions can reduce by up to 90% the cost of lowering emissions by an amount equivalent to Hawaii's current RPS scheme, due to the greater range of abatement options offered by the CES.

In response to growing interest in the CES, a number of modeling studies at the national level have emerged, including Paul et al. (2012), Rausch and Mowers (2012), and Mignone et al. (2012). These papers all agree on the broad consequences of a CES to the electric sector, namely, a shift away from fossil fuels to nuclear and wind, and revenue transfers from fossil heavy states to those states with large renewable resources. Mignone et al. and Rausch and Mowers use models with macroeconomic modules, and thus can also show the impact on GDP and welfare. Mignone et al. find the impact on welfare to between \$287B and \$355B (cumulative NPV in 2009 \$) through 2035; Rausch and Mowers using the USREP integrated model additionally find the policy hits welfare harder in the lower income brackets. Finally the Energy Information Administration has conducted an analysis of the Bingaman proposal using the NEMS model (EIA, 2012). In their reference case, they concluded there would be little impact on electricity prices until 2020, and that nuclear generation would dominate new generation as the standard tightened. There was a modest impact on GDP of less than 0.1% by 2050. Their case found lower interregional transfers and low use of Alternative Compliance Payments, due to the dominance of nuclear, and due to restrictions on credits from legacy generation (discussed further below).

The Energy Modeling Forum (EMF) 24 study, in which multiple energy-economy models were asked to run a set of coordinated scenarios for future U.S. climate policy, included a CES

3. Under Bingaman's proposal, for example, credits per MWh would be awarded to generators according to the following formula: 1 – (carbon intensity in tCO2/MWh of generator / 0.82). 0.82 tCO2/MWh corresponds to a relatively modern coal-fired unit, so that only generating units with lower carbon intensity than this benchmark would receive credit (there is no "negative" crediting for higher intensity generators).

alongside both economy-wide emissions caps and more specific regulatory approaches. In this paper, we follow the EMF 24 design using the US-REGEN model to explore the economic and environmental outcomes of a CES in relation to other options, with an emphasis on the role of technology. We find that alternative assumptions about technology can completely change the optimal compliance strategy and economic impact at the national and especially the regional level. The unique features of the model's design are applied to yield insights into the nature of a CES approach and how it differs from previously studied market-based carbon policies.

2. MODEL

Overview

Our analysis employs the US-REGEN model, an inter-temporal optimization model of the US economy through 2050 that combines a detailed dispatch and capacity expansion model of the electric sector with a dynamic computable general equilibrium (CGE) model of the rest of the economy. The model emphasizes details in the energy production sectors and different end-uses. Both the electric and CGE models are disaggregated into 15 state-based regions, and the two components are solved iteratively to convergence. The model has been developed over the last two years at the Electric Power Research Institute (EPRI). Because the model has not previously been presented in the literature, we take some time here to describe its key features. Further detail can be found in the US-REGEN Model Documentation (EPRI, 2013).

The electric sector component is formulated as a linear process model with a bottom-up representation of power generation capacity and dispatch across a range of intra-annual load segments. In each time step, the model makes decisions about existing capacity (carry forward, retrofit, or retire) and investments in new capacity both for generation and inter-region transmission, as well as dispatch decisions for installed capacity in each load segment. A discount rate of 5% is applied. Individual existing generators in each region are aggregated into larger capacity blocks based on similar operating characteristics. The block is dispatched as a single unit, but the age profile of the underlying individual units is preserved. Several unique features of the electric sector make the explicit treatment of capacity vs. dispatch essential to accurately model decision-making and the impact of new policies. First, the "shape" or hourly profile of end-use demand and variable resource availability is crucial for appropriately characterizing the operational patterns and profitability or value of different types of capacity. Second, these patterns and hence the value of generating assets are also dependent on the mix of installed capacity in a region (and in neighboring regions). Third, capital investments in generating capacity tend to be long-lived, creating a strong link between dispatch and investment decisions across time periods.

The CGE component of the model is formulated in the classical Arrow-Debreu general equilibrium framework, which describes the supply of factor inputs (labor, capital, and resources) owned by households to the producing sectors of the economy, and the supply of goods and services from these sectors back to households. US-REGEN has been designed with particular detail in the energy sectors and energy flows throughout the economy, with a high level of aggregation elsewhere. Non-energy production is described by an industrial sector, a commercial services sector, and a transportation sector. Household consumption is described by a residential sector with a single representative household. For each sectoral activity, a constant elasticity of substitution production function defines how inputs can be translated into outputs, including the structure of substitution opportunities. There is inter-regional domestic trade in industrial goods and commercial services, and foreign trade in all commodities. Capital stocks accumulate as a function of endogenous investment. Each region's welfare, representing its households' utility, is a function of residential consumption over time.

The representation of the operational details of the electric sector allows a high-fidelity treatment of the trade-offs among candidate technologies under a policy scenario such as a CES, while the integration with the CGE representation of the economy allows a comprehensive analysis of feedbacks between sectors and overall cost effectiveness. The following subsections provide additional detail into a few specific elements of the model formulation. For the electric sector, we describe the treatment of intermittent renewable resources and the distinction between cost-of-service regulation and competitive electricity markets at the regional level. For the macro model, we describe the unique formulation of end-use specific energy-using capital inputs. Additional details, including regional definitions, cost and performance assumptions for new technologies, and elasticity parameters are presented in the paper's appendix.

Intermittent Renewable Resources

Modeling intermittent renewable resources requires particular care because of their spatial and temporal variability. Spatial variability is relevant because of the costs and constraints involved in long-distance power transmission. Temporal variability is relevant because of the much higher costs and more limiting constraints involved in electricity storage. A major motivation for developing a US model with regional detail is the ability to describe the location of renewable resources relative to the location of load centers. For this purpose, we collaborated with AWS Truepower to develop hourly wind and solar output data for the lower 48 states based on meteorology during the period 1997–2010.[4] Wind output was calculated for over 5,000 sites, starting with the most viable and excluding protected and developed areas, to obtain an exhaustive estimate of the realistic potential for on- and off-shore capacity. Output profiles were then aggregated from the site level into eight classes by state for onshore (one class for offshore) in terms of quality (i.e. capacity factor), and from states into model regions. A similar screening process was used to determine the amount of land area available for central-station solar photovoltaic (PV) or concentrating solar power (CSP) deployment in each state, excluding protected and developed as well as excessively sloped land. Available land was ranked by resource quality, and due to the extent of the resource potential, detailed profiles were developed for the top 1% of available land. Two classes of profile were developed for regions with distinct solar regimes with one aggregated class developed for others. A separate dataset was developed to estimate the extent of rooftop PV potential, with one class profile aggregated to the state level based on hourly data from 300 cities.[5]

The output profiles were based on particular technological assumptions. For wind, generators were assumed to be 1.5 MW turbines with an 80 meter hub height. A minimum site size of 100 MW was enforced, and terrain and wake effects were included, as well as generator cut-offs at minimum and maximum wind speeds. For central-station and rooftop PV, performance was based

4. In this paper, we use the output profiles based on 2010 meteorology, the same year as the load profile, to ensure synchronicity and correlation is preserved and to avoid damping variance through multi-year averaging. Although there is considerable inter-annual variability, the 2010 profiles are in the middle of the distribution.

5. The total potential capacity for wind and solar in our dataset is very large (roughly 1,400 GW for wind, 3,500 GW for central station solar, and 1,200 GW for rooftop solar), almost certainly larger than any optimal deployment levels, i.e. the ultimate capacity constraint is not binding. However, particularly in the case of wind, the highest quality classes are only available in certain regions with relatively small potential capacity, and the constraints on these classes are often binding.

on a fixed-tilt crystalline silicon technology. For CSP, a parabolic trough system with six hours of thermal storage was assumed. To account for the effect of built-in storage, we derive a production profile for CSP based on the direct normal irradiance data underlying the PV hourly profile assuming the producer maximizes revenue under a flat electricity price.[6]

Although the raw resource data was developed at the hourly level, it is currently computationally intractable to solve an intertemporal optimization over 10 times steps, 15 regions, and roughly 30 existing capacity blocks plus 30 new technology candidates with an intra-annual shape that includes all 8760 hours. However, it is clear that the combined hourly datasets for wind, solar, and load provide crucial information about temporal variability that directly impacts the appropriate valuation of renewable energy investments. The modeling challenge here is to preserve this information while reaching a solution in reasonable time.[7] Our approach is to choose a set of "representative hours" that emphasize the extremes of the joint distribution in order to capture the key moments during a typical year driving capacity and energy needs. We find that by strategic selection of the representative hours, the resolution of the intra-annual shape can be reduced by a factor of roughly 100 without significantly distorting the implications of joint temporal variability between load and renewable availability across regions.[8]

The selection method is based on the premise that the "corners" of the joint distribution are the most relevant, for example, an hour in which load is near its maximum but wind is near its minimum. We use an integer program to determine the minimum number of hours such that at least one hour is sufficiently close (in the sense of a Euclidian norm) to each of the eight corners of the joint load-wind-solar distribution in each region. For a maximum qualifying distance of 5% of the maximal value, the algorithm found a "spanning" set of 44 individual hours. We then add two hours explicitly corresponding to the peaks of the Eastern and Western interconnects, since the integer optimization can choose hours toward the edge of the qualifying "bubbles" around each corner. Finally, to ensure that the interior of the distribution is adequately sampled, we use a clustering algorithm to choose 40 additional hours that best describe shoulder and base conditions. This process results in a total of 86 segments to describe the year. Finally, we choose weights for these segments using an optimization that requires the sum of weights to equal 8760 and minimizes the errors between the 8760-hourly and 86-segment load duration curve and resource duration curves for each region.[9] This method can be shown to successfully preserve, to a first order, the inter-relationship

6. In a model with full hourly resolution, it would be possible to allow endogenous deployment of CSP with storage against actual scenario prices. However, because of the aggregation of hourly segments discussed next, it is necessary to derive a "storage-enhanced" CSP profile a priori using an exogenous price path, assumed to be flat by default. In practice the derived profile intuitively matches expected optimal deployment of storage, with 100% output during peak hours and 0% at night, so this simplification comes at little cost.

7. A static instance of the model describing a single year can be solved in reasonable time with 8760 hour resolution. We consider "reasonable time" to be maximum 2–3 hours per instance to facilitate interactive research and analysis. We are using the CPLEX barrier method with 6 parallel threads (acceleration seems to decline rapidly with further parallelization) on a 64-bit PC with a 3.x GHz multi-core processor and at least 8 GB of RAM.

8. A typical approach in similar models is to use a load shape of approximately 4–10 segments, for example peak, shoulder, and base, possibly with seasonal dimension. While this coarse resolution may be sufficient for capturing a load profile in a single region, the introduction of multiple regions and even more so renewable resource profiles, which in fact have much wider distributions than load, necessitates many more segments.

9. We additionally assign monthly availability factors and variability coefficients for other technologies to segments according to the month in which the representative hour occurred. Because the hours we choose are reasonably well spaced across the year, there is relatively little distortion in the annual averages.

between renewable resources and load. The model documentation (EPRI, 2013) describes this method in more detail.

Cost-of-Service Regulation

The other design feature we describe in more depth is the treatment of cost-of-service regulation. It is well known that a standard optimization formulation of the electric sector in fact corresponds to a perfectly competitive market. This result is due to the second fundamental theorem of welfare economics, which holds that any efficient allocation of resources can be obtained by a competitive market equilibrium, under certain important conditions such as perfect information and convexity. Thus the default formulation for a model of this type essentially treats all regions as competitive. To represent the reality of cost-of-service regulation in many parts of the US, a model therefore needs to move away from a pure optimization. In particular, this type of regulation leads to prices based on average rather than marginal cost, which violates the conditions of an optimal solution (or equivalently a competitive equilibrium). Very few large-scale models of the US electric sector have attempted to account for the effects of cost-of-service regulation, yet it has important implications for the impact of environmental regulations on the price of electricity and by extension the magnitude and distribution of the cost of these policies.

Our approach to incorporate cost-of-service regulation in particular regions begins by assuming that investment and dispatch, i.e. the supply side of the electric sector, are chosen to minimize total system cost regardless of whether rates are regulated.[10] Only the price seen by the end-use customer depends on the presence of regulation. In competitive regions, the generation component of the retail price is equal to the energy-weighted annual average marginal wholesale price.[11] In the pure optimization, this is exactly the price at which the inverse demand function is evaluated (for now we do not allow price responsiveness in individual segments, only at the annual total, i.e. as a proportional scaling of the annual profile). By contrast, in regions with cost-of-service regulation, the generation component of the retail price is an energy-weighted average of all variable costs plus a charge for capital investment recovery. This is *not* the price at which the inverse demand function is evaluated – thus the necessary adjustment must be to the demand function in cost-of-service regions.

We calculate the appropriate adjustment by taking advantage of the iterative solution procedure between the electric and macro model components. At the end of an iteration of the electric model, an ex post cost-of-service price for each regulated region is calculated by adding all variable expenditure (e.g. fuel and operation costs), including net imports of wholesale power and compliance credits in certain policy scenarios, plus a rate base for investment recovery. The rate base consists of a revenue requirement for existing capital calibrated from reported retail prices in 2010 less modelled variable costs and depreciated to zero by 2025 plus a recovery allowance for new

10. While this seems to be a reasonable first-order assumption, we note that some authors have found contrasting evidence, for example Fabrizio, Rose, and Wolfram (2007) .

11. The optimization ensures that capacity costs are reflected in a (very high) hourly energy price in the peak segment or segments. Although in practice most competitive market structures use a capacity market to avoid energy price spikes, our formulation is equivalent in the deterministic context, thus it is suitable to interpret our annual average marginal wholesale price as comprising a payment for both energy and capacity. A more true-to-life treatment of capacity markets, which are characterized by uncertainty and often the potential for strategic interaction between firms, is beyond the scope of our methodology. Again, our formulation corresponds to perfectly functioning competitive markets in which total system costs are minimized.

investment. The new investment recovery schedule ensures that the discounted sum of recovery revenue is equal to the value of the initial investment, and that the asset is depreciated uniformly (i.e. straight-line) over 30 years (20 years for retrofit investments). At the same time, the competitive (i.e. marginal) price observed in the model solution (typically higher than the constructed price) is stored for the next iteration of the electric model. It is the constructed price that is passed to the macro model as the benchmark for electricity service demand in the end-use sectors. However, when the macro model solution's quantity of electricity demand is passed back to the electric model for the next iteration, that quantity combined with the *competitive* price from the previous iteration is used as the reference point of the demand function, as described in Böhringer and Rutherford (2009). In this way the optimization framework may still be used to describe supply-side decisions, but the solution algorithm will converge at a level of demand consistent with regulated prices.

It is important to note here that even regions with competitive electricity markets may not be perfectly competitive. Various forms of market failure or market power may be important factors in shaping outcomes, and these phenomenon are not present in an optimization-based formulation of a competitive market (since only a perfectly competitive market coincides with the optimal outcome). By the same token, the process by which regulated rates are constructed can be idiosyncratic and in some cases subject to manipulation, which our simplified approach admittedly ignores. Nonetheless, our approach captures the essential features of both, and the essential distinction that both marginal and inframarginal cost increases result in price increases in regulated regions, whereas only marginal cost increases are transferred in competitive regions. A final caveat: the approach here is designed to appropriately reflect the implications of extant regulatory structure for environmental policy; it is neither able, nor intended, to inform choices concerning rate regulation itself.

Energy-Specific Capital

Finally, we describe briefly the representation of energy services and energy-specific capital in the macro model. Energy services refer to a composite bundle trading off energy-specific capital services with energy demand in the form of fuel purchases. Energy service bundles are inputs to industrial and commercial production, non-passenger vehicle transportation, and residential consumption. Alternately, a process model is used to model the passenger vehicle transportation sector. Within a sector, distinct end-use categories are represented separately (see appendix for nesting structure and category definitions). For each major fuel-end-use combination within a sector, an energy service is defined linking fuel use to an energy-specific capital demand representing the associated energy-using equipment. The elasticity for this nest describes substitution opportunities between energy-specific capital and energy use, for example, a more expensive light-bulb that uses less electricity per lumen or a more expensive furnace with a higher thermal efficiency. This structure allows an explicit representation of improvements in energy efficiency, that is, reductions in energy use per energy service unit, as distinct from reductions in service demand itself.[12] Improvements can be embedded in the baseline, and further price- or policy-induced improvements are described by the choice of elasticity. This parameter can vary across uses and fuels to reflect different underlying technologies and opportunities for improving end-use efficiency. Estimates in the literature of the overall capital-energy elasticity in the economy are roughly clustered around a value

12. Such a structure is uncommon among CGE models. One exception is Laitner and Hanson (2006), who use a similar representation for energy-use-specific capital inputs.

of 0.3 (see for example Ogakawa & Ban 2008, Beckman et al. 2011); but these estimates include all capital, not just end-use capital. We currently consider a range of choices from 0.1 to 0.5.

This formulation requires an assumption about the value share of energy-specific capital within the energy service bundle. We again rely on a top-down estimate, as opposed to a bottom-up calculation based on equipment stock data. While this figure can vary substantially across different applications, we currently use a rough estimate of 0.5 for all instances of the energy service bundle. That is, we assume that an energy service unit consists of equal parts capital payments and fuel purchases.[13] The resulting capital service value is "deducted" from the larger capital pool of which it is a sub-component so that total capital demands remain the same.

Importantly, the energy demand component of energy services corresponds to fuel purchases at retail prices. One important feature of fuel markets is that retail prices vary across sectors and particularly in the residential sector are typically substantially higher than wholesale prices. These price gaps or "margins" are observed explicitly in the benchmark energy data, and the model design must be able to accommodate them in a coherent way. When a fuel is produced by either a primary or a secondary energy sector, the output price is defined as the wholesale price (for example, the wellhead price of natural gas or the refinery gate price of gasoline). When a fuel is purchased by another sector, the price of the input is the retail price for that sector (for example, the price of natural gas paid by residential customers or the price of gasoline at the pump). The reason for the "margin" is that an additional service is being provided to bring the fuel from the point of production to the point of consumption, and the retail customer must purchase this service along with the wholesale fuel purchase. We regard this "margin" as a demand for commercial service output and include it in fixed proportion to the fuel demand within the energy service bundle.[14]

3. SCENARIOS

The CES scenario we implement in this paper follows the specifications of the EMF 24 Study on US technology and policy scenarios. Our definition of qualified generation includes all renewable technologies (hydro, wind, solar, and biomass), nuclear, natural gas, and fossil with CCS. Both new and existing sources qualify.[15] Renewable and nuclear generation receives full credit, while fossil with CCS has a weight of 0.9 and natural gas without CCS has a weight of 0.5. The target pathway follows a linear schedule from the current level of roughly 40% (20% nuclear, 10% renewable, 20% $\times$ 0.5 natural gas) to 80% in 2035 (the Obama Administration's nominal goal) and 90% in 2040 and thereafter. As specified in EMF 24, we apply the CES to the electric sector with no accompanying policy constraints on the rest of the economy. For comparison purposes, we draw upon the suite of EMF24 economy-wise market-based carbon policy scenarios, specifically the scenario with a 2050 emissions target 50% below 2005 levels, with no international offsets allowed.[16]

13. Development is underway to coordinate with bottom-up technology evaluations to allow a data-based choice of both elasticity and value share parameters for each fuel and end-use.

14. One could more rigorously define the wholesale-retail margin for fuels as a combination of commercial and transportation services. More data development would be required before introducing this refinement.

15. While similar to the Bingaman Proposal in many details, the scenario based on the EMF specification excludes certain provisions proposed by Bingaman to limit crediting of existing clean energy sources, and cost-containment measures such as banking of credits and availability of alternative compliance payments.

16. EMF Scenario numbers US03 and US04

Table 1: Description of Technology Scenarios

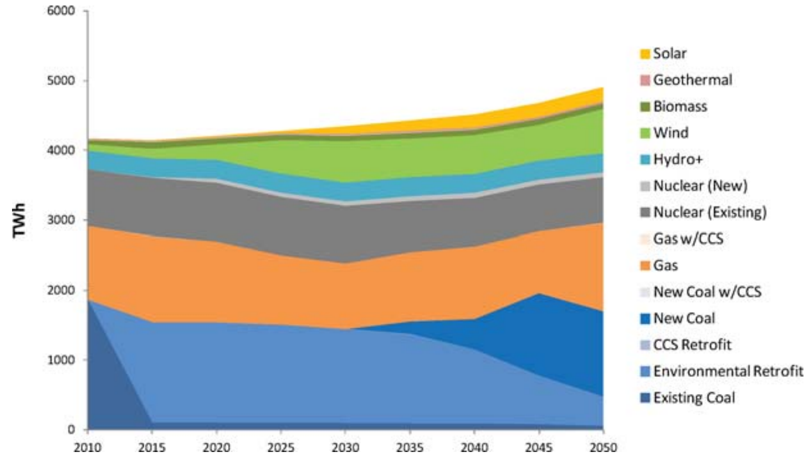
Case Name (EMF #)	Default (US13)	1 – GAS	2 – NUC (US02)	3 – CCS	4 – RNW (US01)	5 – HIC (US23)
Natural Gas Supply	AEO 2011	AEO 2011 - $2	AEO 2011	AEO 2011	AEO 2011	AEO 2011
Wind and Solar	Faster cost declines	Faster cost declines	Moderate cost declines	Moderate cost declines	Faster cost declines	Moderate cost declines
Inter-Regional Transmission	Available	Available	No	No	Available	No
Nuclear	Existing Extended New available	Existing Extended New available	Existing Extended New available	Existing < 60 yrs No new	Existing < 60 yrs No new	Existing < 60 yrs No new
CCS	New / retrofit available	New / retrofit available	New / retrofit available	New / retrofit available	No	No
Energy Efficiency	High	High	High	High	High	AEO 2011

Along a separate technology dimension, we consider several possible futures for the costs and availability of alternative generation options in the electric sector. In the default scenario, we make generally optimistic assumptions about all technologies: aggressive cost declines for renewable generation; no constraints on new nuclear and CCS generation (other than a national build rate limit for nuclear and some regional constraints on geologic storage capacity); no constraints on new inter-regional transmission (other than investment cost); and accelerated improvement in energy efficiency on the demand side. We then consider several sensitivity cases in which these assumptions are varied sequentially. The first alternative case considers a lower price of natural gas. The second considers more pessimistic assumptions about renewable technologies, in particular no new inter-regional transmission. The third considers a case with no new nuclear (other than plants currently under construction), as well as an upper bound of 60 years on existing nuclear licenses. The fourth considers a case with, in addition to these nuclear constraints, no option for CCS. Finally, we consider a fifth sensitivity with all pessimistic assumptions about cost and availability, as well as a higher load growth tracking the AEO 2011 reference projection rather than the accelerated improvement path included in the default case. Table 1 describes the technology scenarios considered in this paper.[17]

Underlying each of these scenarios is a no-carbon-policy baseline with corresponding technology assumptions. In the baseline, economic growth, fuel demand, and fuel prices are calibrated to approximate the reference case in the EIA's Annual Energy Outlook (2011). However, the fuel mix in the electric sector and the price of electricity along the baseline reflect endogenous US-REGEN outcomes (using AEO 2011 electricity demand and fossil fuel prices as calibration inputs). In addition to formulation differences between US-REGEN and the National Electric Modeling System (NEMS) used to produce the AEO, there are two important scenario differences as well between our baseline the AEO 2011 reference case. First, we enforce several pending non-CO2 regulations on existing coal generators in the 2015–2020 timeframe. Coal units can choose to

17. Note that the EMF 24 scenario specification only included two variations of the technology space for the CES policy scenario: The pessimistic renewable case (US28, our Sensitivity 2) and the pessimistic nuclear and CCS case (US27, our Sensitivity 4). In this paper we examine the CES under a broader range of technology futures.

Figure 1: U.S. Total Electric Generation in Baseline with Default Technology



retrofit (the cost of which varies significantly by unit), retire, or convert to natural gas combustion. Units that stay operating may be further retrofit with CCS in later years. A separate report details the methodology and results of the modeling of environmental controls in US-REGEN (EPRI, 2012). The Clean Air Act (CAA) requires new fossil units to meet (generally tighter) standards as well, and we include the cost of compliance with these standards in the total capital cost of building a new unit. However, the second difference from AEO is that our baseline does not incorporate any expectations of future climate policy, or of regulatory uncertainty from other possible environmental legislation, such as the CAA. The result is that the baseline in this analysis includes a substantial build of new coal generation through 2050. In this regard we differ significantly from the AEO 2011 reference case, which projects negligible amounts of new coal built after 2015 (up to 2035), apparently due to a cost adder intended to reflect a non-specific future climate policy.

Figure 1 shows baseline electric generation through 2050. There is a steady rise in electric sector CO2 emissions, with much of the new capacity added being either gas or coal. Wind has a steady penetration, initially driven by state RPS constraints but later by economics as costs decline. Solar similarly sees penetration in later years, particularly due to rooftop PV in regions with a greater spread between wholesale and retail electricity prices (such as California and New York).

4. RESULTS

We first examine results of a CES scenario under default technology assumptions. Figure 2 shows the national generation mix, in which a suite of technologies play a role in meeting the CES requirements. The major contribution is from renewable sources. The increased reliance on wind in particular is accompanied by a vast expansion of inter-regional transmission and increased total installed capacity. Nuclear also plays an important role, with some gas generation serving peak load and offsetting lulls in intermittent generation. The small contribution of CCS technologies is noteworthy – this result is due to low gas prices, aggressive cost declines in the cost of wind and solar, relatively low demand growth, and our default assumptions containing few hindrances to nuclear power.

4.1 Sensitivity 1: Lower Gas Prices due to Shale

One important question to consider, given the recent technological developments in the extraction of natural gas in the United States, is how the outcomes might change if gas prices

Figure 2: US Total Electric Generation under a CES with Default Technology

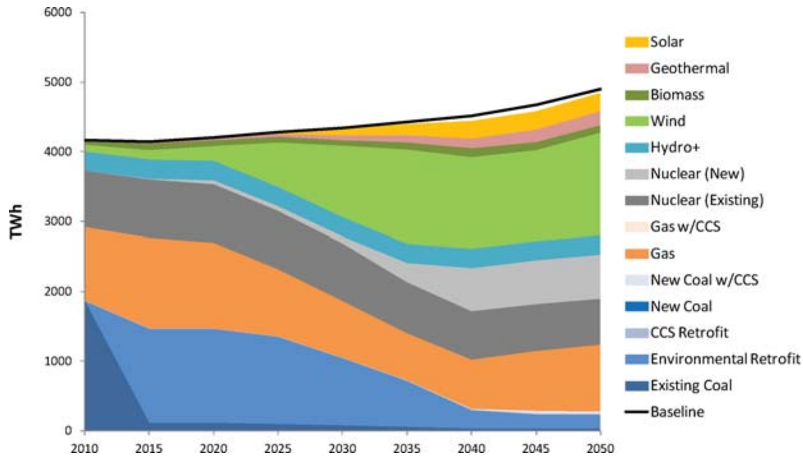
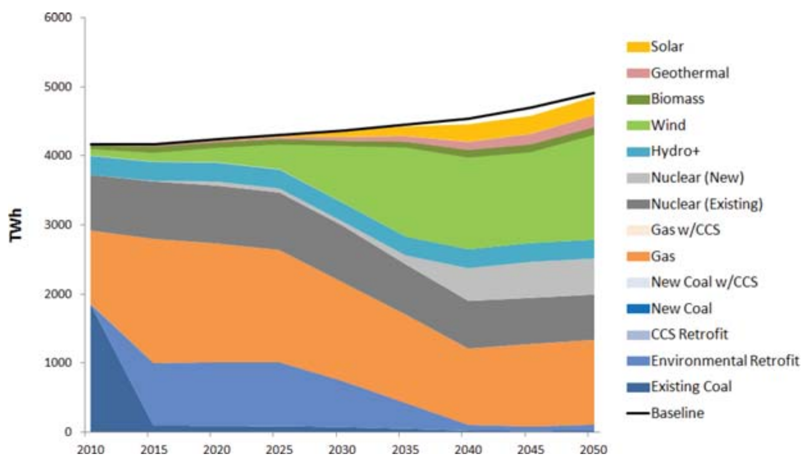


Figure 3: US Total Electric Generation under a CES (GAS scenario)



remained low into the foreseeable future as a result of sustained access to low-cost domestic supply. In Sensitivity 1, we consider this possibility with a recalibration of our macroeconomic baseline to gas prices $2 per mmbtu lower for the same forecast quantities from 2015 onwards. We refer to this case as the GAS scenario. Figure 3 depicts the results, which show only limited differences relative to the default case with the (already low) AEO 2011 gas price path. There is a marked increase in gas generation, as expected, but this reflects an enhanced competitive advantage over existing coal, in particular a sharp reduction in the amount of retrofits for environmental compliance in the near term. In the long run, the incentives introduced by the CES override the low gas price, as the relative proportions of gas, nuclear, and renewables in 2050 are largely unchanged.

4.2 Sensitivity 2: Pessimistic Renewable and Transmission Assumptions

Next we consider a future in which new nuclear and CCS are available, but the optimistic cost declines for renewable technologies and more importantly the ability to expand inter-regional

Figure 4: US Total Electric Generation under a CES (NUC scenario)

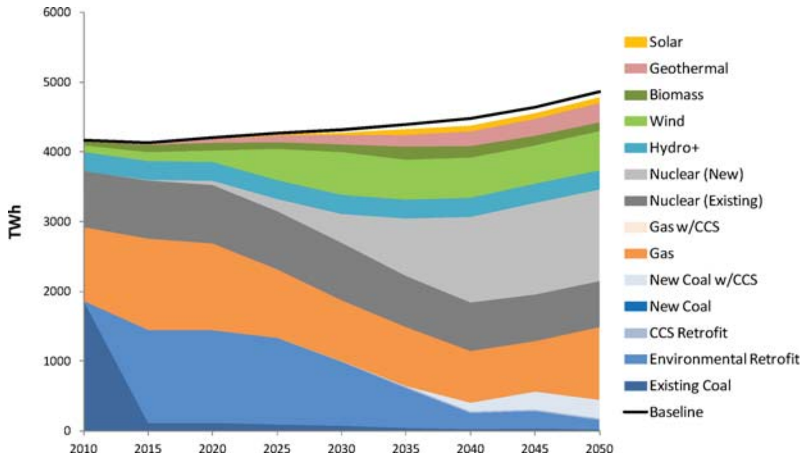
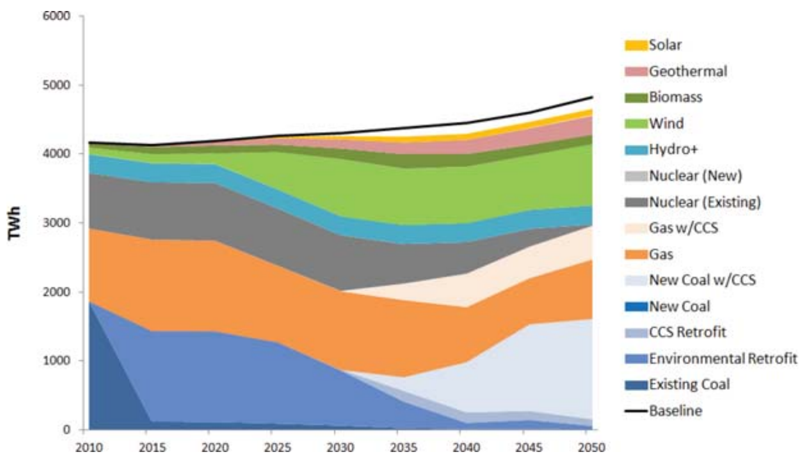
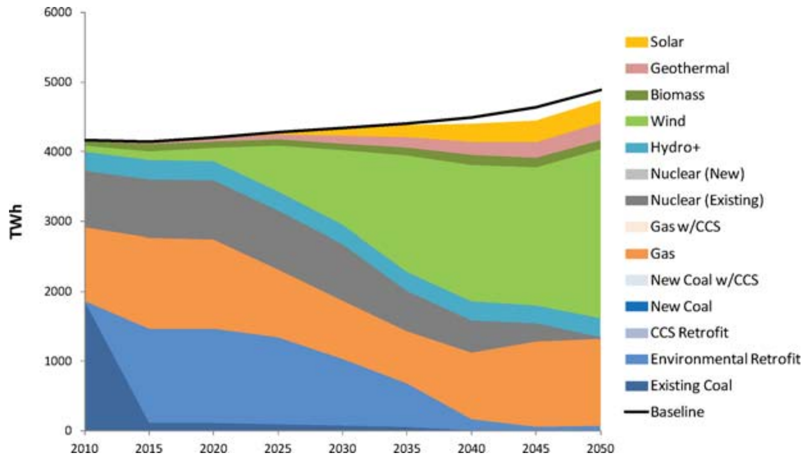


Figure 5: US Total Electric Generation under a CES (CCS scenario)



transmission infrastructure do not materialize. The generation mix for this scenario is depicted in Figure 4. In this case, wind deployment reaches a threshold above which it is not optimal to deploy due to the inability to move large amounts of power out of wind-rich regions. Instead, nuclear expands greatly with a new fleet 50% larger than the existing fleet emerging between 2020 and 2040. CCS plays a smaller role but on the whole is out-competed by nuclear. While the capital costs of CCS are lower than nuclear, it has higher fuel and operating costs, and a lower availability factor, and only a 0.9 credit in the CES scheme. Naturally, there is uncertainty about how both of these technologies will evolve. The result here in which nuclear dominates reflects the particular parameterization employed in our model, including the discount rate, as lower rates favor more capital intensive technologies. We denote this scenario NUC because of the central role played by this technology.

Figure 6: US Total Electric Generation under a CES (RNW scenario)



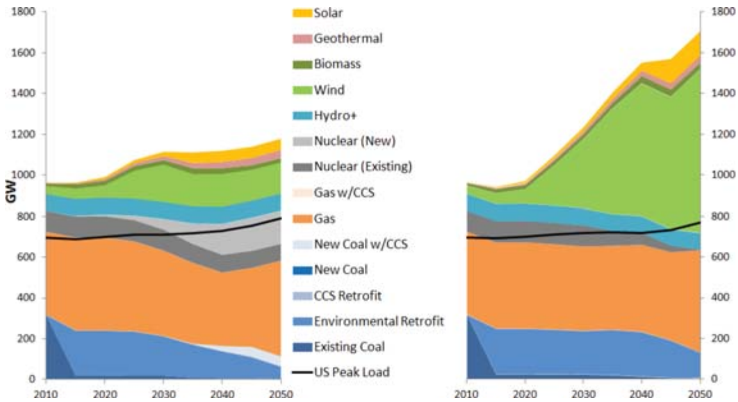
4.3 Sensitivity 3: Pessimistic Renewable and Nuclear Assumptions

To explore further the potential role of CCS, we next consider a scenario which assumes, in addition to slower improvement in wind and solar and limits on new transmission, no new nuclear plants can be built, and no life extensions beyond 60 years are granted for existing nuclear units. Thus we have the previous case, but the preferred generation backbone option (nuclear) off the table. The system adjusts by adopting more wind and solar (again constrained by the existing transmission network and thus relying heavily on local supply), and widely deploying CCS. Both new coal and gas CCS are built, and even some existing coal units retrofit with CCS. Because the CCS is option is more costly than nuclear (in our model), it begins to emerge as an alternative to the local renewable strategy in 2030 rather than in 2020 for nuclear in the previous case. This case is referred to as the CCS scenario.

4.4 Sensitivity 4: Pessimistic Nuclear Assumptions and no CCS

The previous two scenarios have relied alternatively on nuclear and CCS with the assumption that an expansion of inter-regional transmission to accommodate deeper penetration of renewable generation will not be possible. However, there are both technical and political questions about the extent to which new nuclear and CCS can or will be deployed at a large scale in the coming decades, even with an incentive-based policy such as a CES. Meanwhile, renewable technologies enjoy broad support, and in particularly in the case of solar, technological advances continue to yield cost and performance improvements. Although siting new long-distance transmission is notoriously difficult (Vajjhala and Fischbeck, 2006), our modeling indicates that in the presence of a CES or other policy favoring low-emitting generation, it is likely a good investment. We therefore now consider a future in which new nuclear plants and CCS technology are not available due to regulatory and/or technical reasons, but that inter-regional transmission can be built and that aggressive cost declines for wind and solar are realized. We denote this future the RNW (renewables) scenario, due to the dominance of renewables in the resulting generation mix. The generation mix for this case is depicted in Figure 6.

Figure 7: US Total Installed *Capacity* under a CES: NUC (left) and RNW (right) scenarios



This case illustrates how the treatment of variable renewable resources, outlined in Section 2, translates into results for scenarios with a high demand for electricity from wind and solar power. The representative hour methodology ensures that hours during the year where electricity demand is high, but output from renewable resources is not available, are incorporated into investment, dispatch and retirement decisions.[18] The implications of this methodology on capacity requirements are significant, as highlighted in Figure 7, which presents installed capacity under the NUC and RNW cases. In the RNW case, the optimal level of installed capacity is almost double peak load. There are two reasons for this. One is simply that wind has a far lower capacity factor than thermal generation, and thus requires additional nameplate capacity per energy output. The other reason is that wind generation, heavily deployed in this scenario, provides essentially only energy value, with almost no capacity value at the peak. In our underlying dataset of wind output, based upon 2010, there was at least one high pressure event over the Midwest, during which wind speeds were close to zero for several days but loads were near peak. We find such high pressure events to be a regular occurrence, if not annually then certainly within the horizon of a utility's planning cycle. Thus there must be additional thermal capacity (in the form of both new gas turbines and delayed retirement of existing coal) on top of the large renewable capacity to serve load in these moments.

4.5 Sensitivity 5: All Pessimistic Assumptions

Finally we consider a scenario in which CCS, new nuclear, and new transmission are not permitted, and there are less optimistic cost declines for renewable technologies. We further omit the 20% improvement in energy efficiency over the standard rate of improvement specified in the EMF24 regulation scenarios. We denote this case the HIC scenario, for high cost, since the economically less favorable variant was selected for all options. The generation mix for this case is shown in Figure 8.

With no new nuclear, no CCS, and no transmission, the model continues to build renewables to meet the CES targets, but it has to build lower value regional renewables, with fewer windy or sunny hours. At the same time, it builds up other expensive generation such as geothermal and

18. We acknowledge that sub-hourly variability can present additional operating challenges to the hourly variability we consider here. A reduced-form operating reserves formulation is a current model development task.

Figure 8: US Total Electric Generation under a CES (HIC scenario)

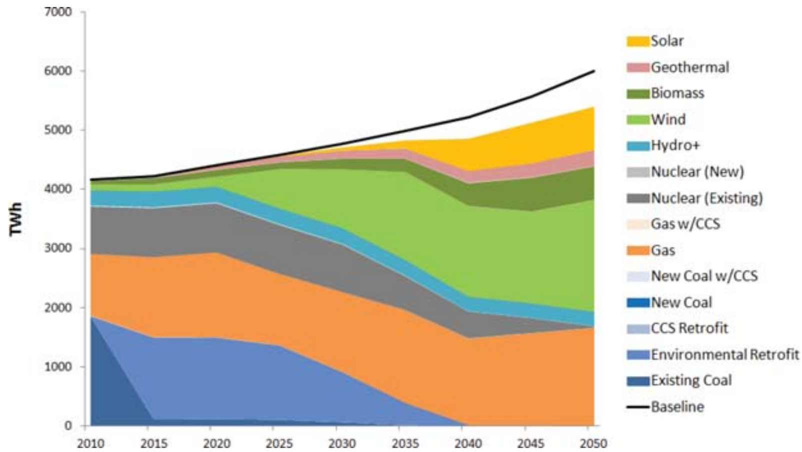
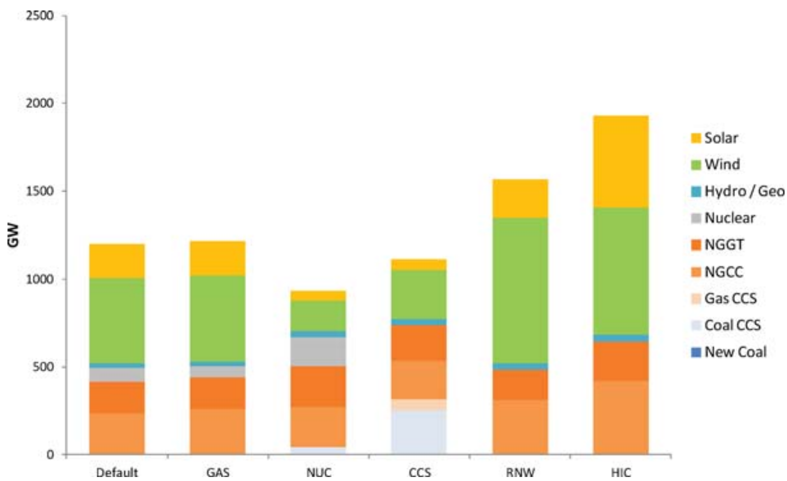


Figure 9: US Total Capacity Additions 2010–2050 under a CES, across scenarios



biomass. Finally the resulting rise in electricity prices causes an increase in energy efficiency and demand reduction from the non-electric sectors. As we will see below, the technological barriers to meeting the CES inherent in this case cause the price of electricity and the price of CES credits to rise much higher than in any of our other cases.

Our six alternative technology scenarios for the same CES policy can be summarized by comparing the cumulative capacity build through 2050 by technology, as shown in Figure 9. This figures reveals that the model prefers to build as much gas as possible within the CES framework. After that, a mix of nuclear and renewables are preferred. CCS is built only if renewables are sufficiently expensive, or unavailable due to lack of transmission, and nuclear is not available. In the HIC case, there is more capacity built overall due primarily to faster load growth (i.e. less energy efficiency in the baseline), but also to more reliance on local renewable generation, which carries a greater capacity requirement.

4.6 Regional Variations and Transfers

For a variety of reasons, the current generation mix in the US varies considerably from region to region. Heterogeneity arises due to factors such as fuel price differences, primarily driven by transportation costs; to a lesser extent, construction and labor cost differences; resource availability, in terms of both renewable energy and water access; geographical or other constraints on transmission; state and local policies; and in some cases public attitudes toward certain technologies, such as nuclear. The electric model in US-REGEN is designed to account for all of these factors: Fuel price deltas relative to the national average reported at the unit level in the base year are carried forward as indicators of relative transportation costs; capital cost estimates reflect a region-specific labor factor for the construction component of investment (although these differences tend to be small in percentage terms); renewable resource variability is extensively captured, as described above; existing transmission constraints and state-level RPS policies are included; and particular technologies are excluded in particular regions (e.g. nuclear in California and CCS in New England).[19] While it would be difficult to reproduce in the model the particular circumstances that led to the investments over the past several decades culminating in the current fleet, going forward the model's cost-minimizing investment criteria subject to a region-specific parameterization can provide insights into the regional implications of a policy such as the CES.

One major implication of the CES is that a credit market is created in which qualified generators receive revenue from compliance-obligated entities, presumably load-serving entities (LSEs). To the extent that qualified generation is not evenly distributed around the country, this will result in financial transfers between regions. We observe that while nuclear and CCS generation can, if available and with a few restrictions, be sited anywhere, renewable generation is most cost-effectively sited in particular resource-rich areas. Thus a major conclusion of our study is that under a CES, regional differences–and transfers–are much more significant when the standard is met through renewable generation (enabled by expanded transmission) than through nuclear or CCS.

To demonstrate, we compare electric generation and net credit revenue under the CES at the regional level in the NUC and RNW technology scenarios. Although the model includes 15 regions, we summarize here by partially aggregating into 8 super-regions. Table 2 defines these regions.

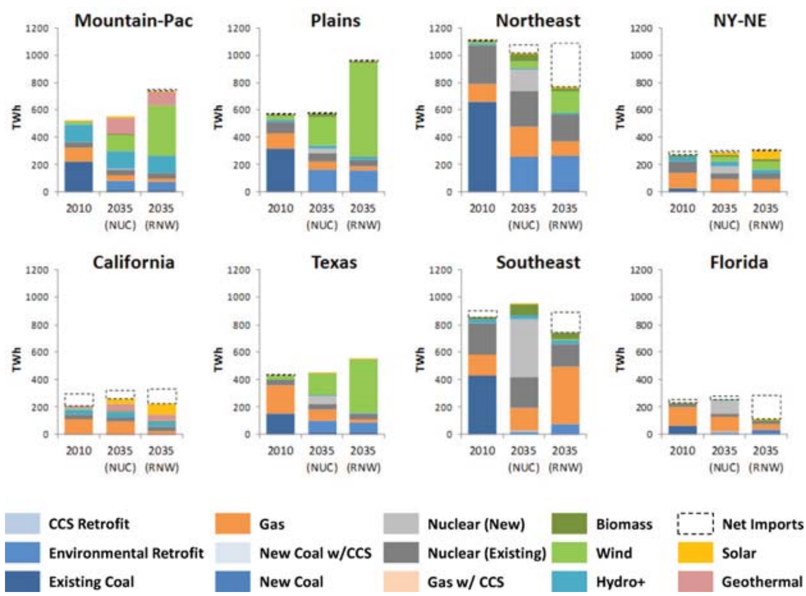
Beginning with generation in Figure 10, the ability to exploit the geographically concentrated renewable resource endowment through expanded transmission in the RNW scenario leads to a nationally optimum solution with large exports of electricity across the country, particularly into the East and South, where local generation sees a marked decrease. By contrast, in the NUC case each region is largely self-sufficient in generation, that is net imports are relatively small. In the NUC scenario, nuclear is deployed most heavily in the Southern regions with poor renewable resource endowments, while those regions in the Midwest and West use their available high quality wind to the extent possible given limits on transmission. When nuclear is restricted, the Southeast must rely instead on natural gas, whereas in Florida, where gas is relatively more expensive, the preference is to expand transmission and import power. The Northeast uses some local wind but also prefers to import from the neighboring Plains states, which enjoy higher capacity factors.

19. While we do not currently track or model water consumption or withdrawals, we did use the results of a joint ORNL-EPRI study to jointly constrain new installations of fossil CCS and nuclear based on regional water availability (the constraints turn out to be non-binding).

Table 2: Definition of Super-Regions for Reporting

Super-Region	States included: [ ] indicates model region groupings
NY-NE	[NY]; [CT,MA,ME,RI,VT]
Florida	[FL]
Northeast	[MD,NJ,PA]; [IL,MI,OH]; [IN,WI,WV]
Southeast	[NC,SC,VA]; [AL,GA,KY,MI,TN]
Plains	[IA,KS,MN,ND,SD]; [AK,LA,OK]
Texas	[TX]
Mountain-Pac	[AZ,CO,NM,NV]; [ID,MT,UT,WY]; [OR,WA]
California	[CA]

Figure 10: Regional Electric Generation in 2010 and 2035 under a CES Policy, NUC, and RNW Cases



Differences in regional generation choices have strong implications for the financial flows associated with a CES policy. Figure 11 shows net CES credit transfers in 2035 in the NUC and RNW case. In the NUC case, the magnitude is smaller, and the net recipients are the Southeast, which invests heavily in nuclear, and the Mountain-Pac region, which is endowed with both high-quality wind and the majority of the country's existing hydro (a qualified source in our scenario). In the RNW case, the magnitude is much larger, and the Plains region becomes a net recipient of nearly $10 billion annually in credit revenue (for comparison, the total wholesale value of generation in that region today is around $30 billion). Another way to gauge the scale is to divide by electricity consumption; the $10 billion works out to almost $16/MWh in 2035 in the Plains region. Mountain-Pac and Texas also benefit, at ˜$15/MWh and ˜$6/MWh respectively, while the Northeast, Southeast, and Florida become large credit (and power) importers.

Figure 11: Net Flows of CES Credit Revenues in 2035 in the NUC and RNW Cases

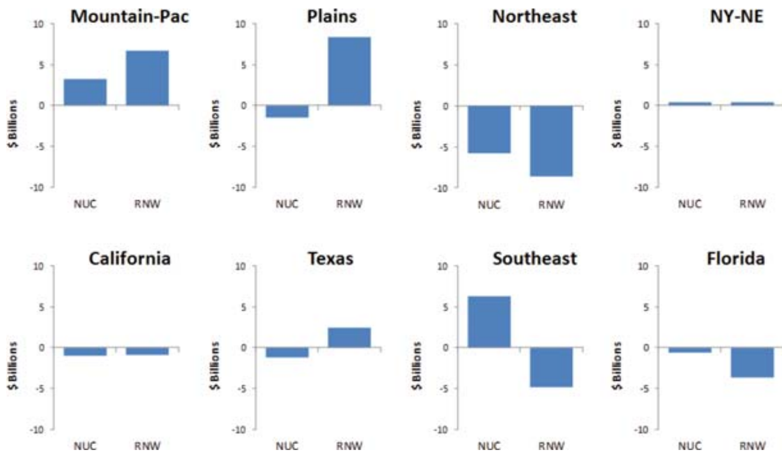
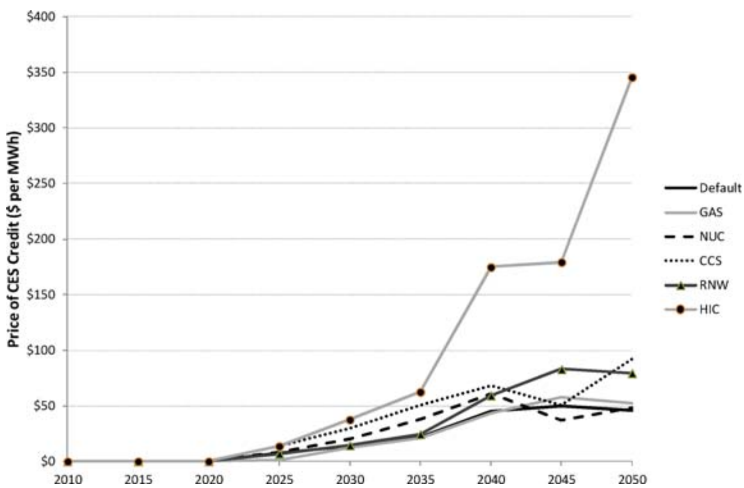


Figure 12: Price of CES Credits (in 2010 dollars)

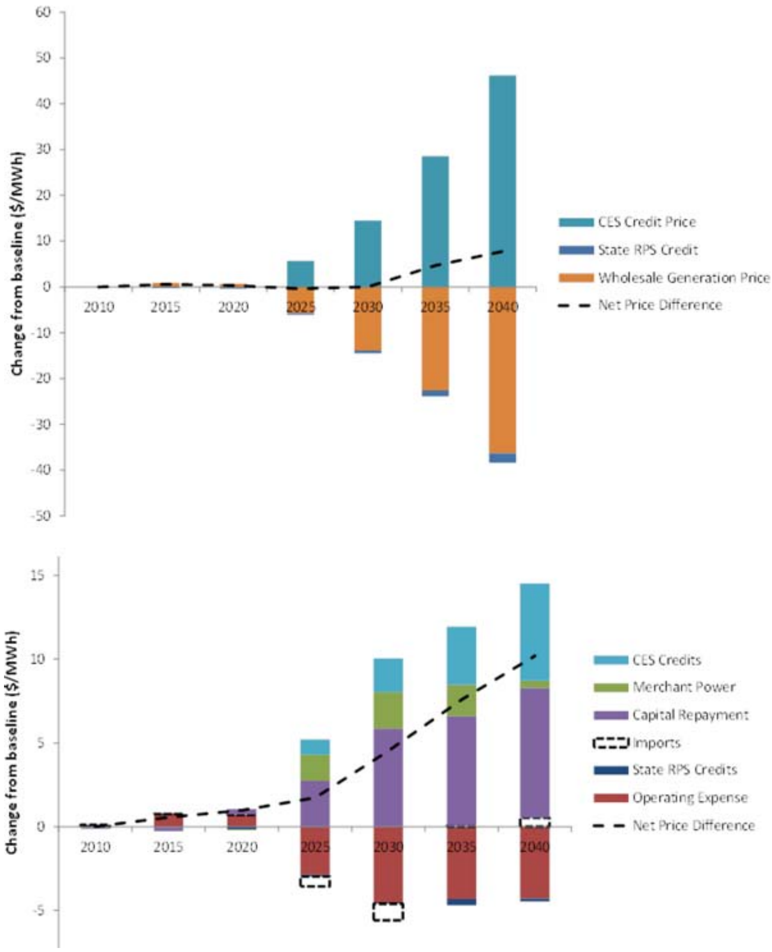


4.7 Credit and Power Prices

Figure 12 illustrates the importance of technology assumptions in assessing the CES credit price. For example, in the HIC case, the CES credit price approaches $300/MWh. With more optimistic energy efficiency assumptions and at least one of nuclear, CCS or renewables/transmission available and able to expand, the price stays below $100/MWh through 2050. The gas price has very little effect on the CES credit price, since the policy discourages gas over time. We also note that CES credits have no value until the CES starts to bite in 2025; that is, the standard's requirement is met in 2015 and 2020 either by baseline investments or by anticipation of the tightening future requirements.

Importantly, the electricity price faced by consumers does not necessarily change in a proportional amount to the CES credit price. Figure 13 illustrates the different mechanisms by

Figure 13: Decomposition of changes in average retail price (a) competitive pricing regions and (b) cost-of-service pricing regions

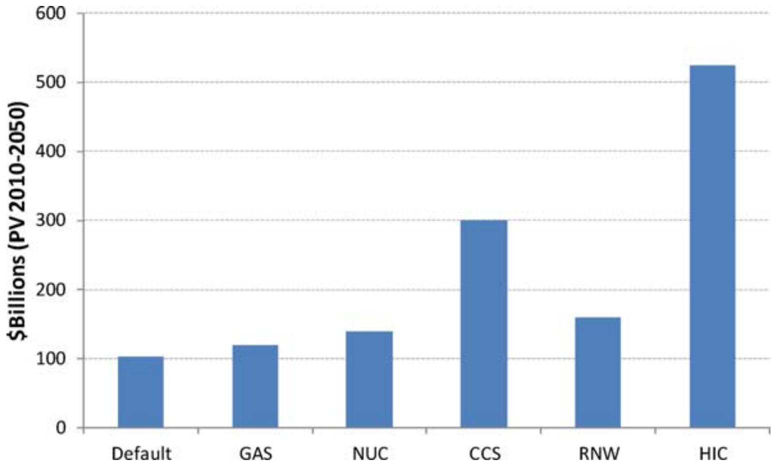


which the CES policy influences electricity price for a sample EMF24 CES case, the NUC case (US28F), highlighting the role of the cost-of-service pricing formulation presented in Section 2.[20]

Figure 13(a) illustrates how the addition of the CES credit adder is offset by an average lower wholesale generation price across competitive pricing regions. This reduction occurs through two channels. First, all clean generation receives a CES credit subsidy per MWh generated. This serves to reduce directly the short-run marginal costs of all clean units including, crucially, the partially-qualified gas-fired units that are most often on the margin, which reduces the marginal price of generating electricity for many hours of the year. Second, the CES credit subsidy increases the incentives to build clean generation, driving in particular a large increase in nuclear and renewables, and a large decrease in coal. The former have low short-run marginal costs compared to coal, again driving down the dispatch curve in all hours of the year. The cost of the CES credit subsidy

20. We emphasize that the purpose of Figure 13 is not to evaluate the rate regulation itself, but to illustrate the different mechanisms through which a CES may affect the electricity price.

Figure 14: Welfare Loss by Technology Sensitivity



is covered by load-serving entities, which pay for the credits when purchasing electricity and include the cost in the retail price. Over time, as the target tightens, the gap between CES credit costs and reductions in wholesale electricity prices increases, with a resulting rise in retail electricity prices.

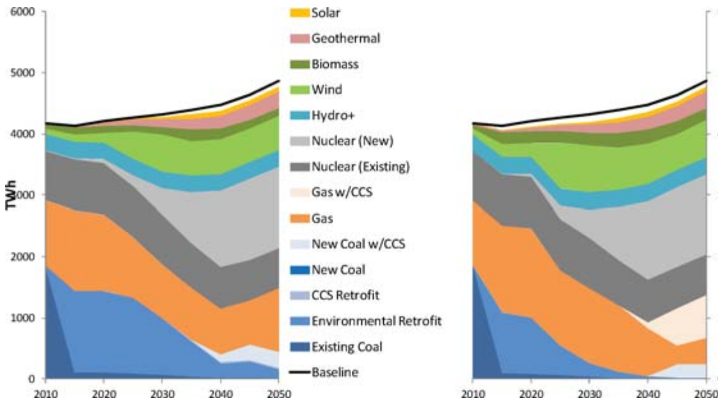
Figure 13(b) illustrates the effect of the CES across regulated regions. The components of the retail price that increase relative to baseline include the cumulative cost of CES credits averaged over each MWh, capital investment recovery, wholesale power purchases, and in some model years, imports of power from other regions. As wind and solar power generators are assumed to be merchant generators, and are spatially distributed, these latter two items would be expected to play a larger role in a case such as the RNW case. The components of retail price that decrease relative to baseline include operating expenses and state RPS credit purchases, the former largely driven by a decrease in the amount of fossil fuel purchased, the latter similarly observed in the competitive pricing regions.

Thus the price increase in regulated regions is greater than in competitive regions, and the different price mechanisms have important implications for existing generators. In regulated regions, capital recovery for existing units will remain embedded in the rate base regardless of their continued utilization. In competitive regions, generators are paid through wholesale energy and capacity markets, and the decrease in wholesale power prices, while offset for customers by the credit price weighted with the target clean energy level, will only be offset for generators who qualify for clean energy credits. Other generators will see a reduction in capital returns relative to the baseline as a result of the policy. In general, the reduced market price for non-qualified generation is the mechanism by which these sources are discouraged relative to qualified sources.

4.8 Macroeconomic Impacts

Figure 14 below presents the net present value of consumption losses (relative to the respective baseline, as defined in Table 1) associated with the CES policies discussed above. The key insight here is the importance of having technological options to meet a CES target. The model's estimate of losses ranges from $100 billion with the most optimistic technology assumptions, to over $500 billion with the most pessimistic assumptions. However, losses are significantly ameliorated with access to either nuclear and CCS *or* access to quality renewables via the ability to expand

Figure 15: CES (LHS) and Carbon Cap (RHS) in NUC Case



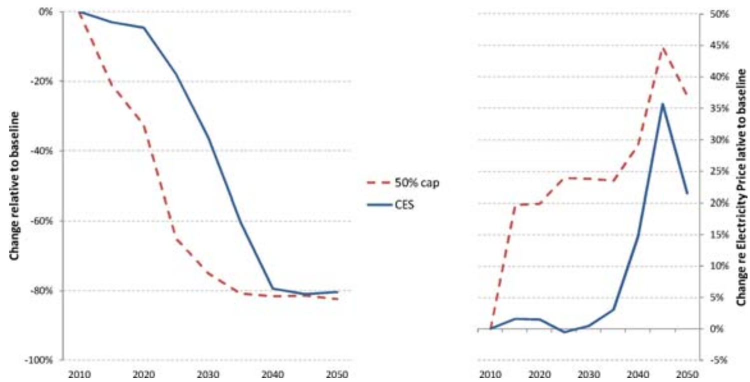
transmission. Another insight that emerges from welfare analysis is the role of the gas price path. Modeled losses in the GAS scenario (with a low gas price path), measured relative to a low gas price path baseline, are over $100 billion dollars, slightly larger than the welfare loss in the default CES scenario, measured relative to the default baseline. The implication is that a low gas price path does not directly cushion the welfare impact of a CES, because it decreases the cost of providing energy in the unconstrained baseline more than under the policy.

5. COMPARISONS TO A CAP AND TRADE SCHEME

We turn now to a comparison between the CES scenario and an alternative scenario in which a cap is placed on economy-wide carbon emissions requiring reductions of 50% below 2005 by 2050 (as defined in the EMF24 scenario specification). The major difference between these two policies is that in the CES there is no regulation of non-electric energy use or emissions, whereas the economy-wide cap places an implicit price on carbon emissions in all sectors. Within the electric sector, as long as the credit weighting approximates carbon intensity, the policies create similar relative incentives among generation technologies. In terms of stringency, we find that the 90% clean energy target for the electric sector leads to a similar reduction in electric generation CO2 emissions when compared to the 50% economy-wide cap (see Figure 16), although this depends on the relative cost of abatement between the electric and non-electric sectors. One feature of the current configuration of the US-REGEN model is that opportunities to reduce emissions from end-use activities are limited, consisting of increased energy-efficiency (capital substitution), inter-fuel substitution towards electricity, and reduced service demand through reduced energy intensity or simply reduced output. Future model development will consider additional options such as bio-energy and carbon capture and storage in industrial applications. In the model results for this paper, 91% of cumulative 2010–2050 abatement occurs in the electric sector in the RNW and NUC 50% cap cases (US03 and US04).

Figure 15 shows the electric generation mix in the CES and carbon cap cases for the NUC technology case. The deployment of renewable and new nuclear generation is very similar in the two cases. Existing coal is phased out more rapidly in the carbon cap case, with natural gas making up the difference. Based on the model's assumed heat rate for new gas combined cycle plants of under 7,000 mmbtu/MWh, this technology is roughly 40% as carbon intensive per MWh as existing

Figure 16: Comparison of Emissions (LHS) and Electricity Price (RHS) under both a CES and a Cap and Trade in NUC Case



coal, thus the carbon cap will create a stronger incentive for gas against coal than a 50% clean energy credit weighting.[21] Moreover, generation from existing coal is particularly sensitive to carbon or clean energy regulation because of the inclusion in the baseline of retrofit requirements for non-CO2 pollutants designed to simulate currently pending or proposed EPA actions.

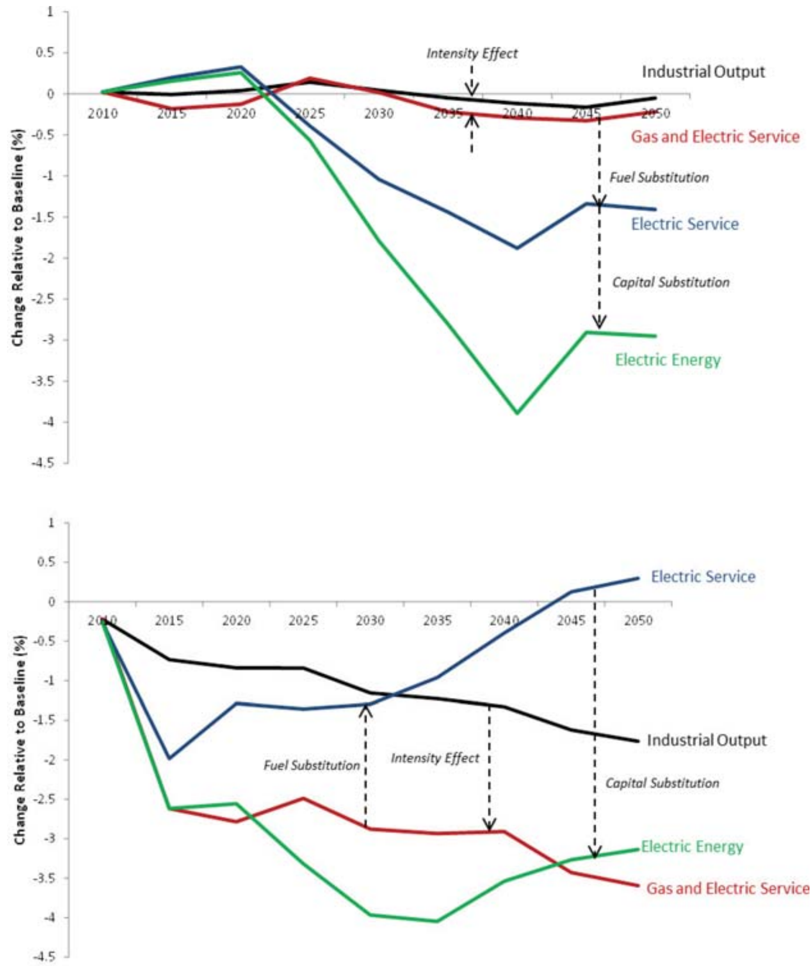
The CES policy in the electric sector leads to an increase in the cost of producing electricity as well as increased demand for natural gas for electric generation (initially). The upshot is that both the electricity price and the gas price faced by consumers in the end-use sectors rise relative to the baseline before 2030, albeit only slightly. After 2030, the electricity price rises more significantly while the gas use for generation, and hence the gas price, fall relative to the baseline, leading to substitution away from electricity and towards gas (and other fossil fuels) at the end use. This results in a small amount of emissions leakage because of the electric-sector-only clean energy regulation. By contrast, there are significant price impacts on all fuels in the carbon cap case, with stronger impacts on gas (inclusive of the carbon penalty), leading to substitution toward electricity.

The end-use modeling structure described in Section 2 allows a nuanced depiction of these effects, shown in Figure 17. Three substitution effects are present: an intensity effect, representing a shift from (to) the energy service to (from) other inputs such as labor and value added capital; a fuel substitution effect, representing the shift from (to) electric services to (from) energy services provided by other fuels; and a capital substitution effect, representing the trade-off between end use electric energy consumption and electricity-specific capital (e.g. the trade-off between an LED and an incandescent bulb). Additionally, there is an overall scale effect driven by changes in sectoral output.

Figure 17(a) illustrates these effects for the CES case in the industrial sector. The intensity effect is apparent through a small decrease in gas and electric services relative to industrial output. The electricity/gas dynamics discussed above are visible by comparing the 'electric service' trend with the 'gas and electric service' trend. Additionally, the capital substitution effect is observed through a greater decline in kWh consumed relative to the decline in the electric service. These three effects moving in the same direction in later model years are consistent with a world where

21. Similarly, our CES gives the same rating to gas with CCS as coal with CCS, while a carbon-intensity based policy would recognize the difference in emissions. Alternative formulations of the CES have been proposed that tie a generator's credit explicitly to annual CO_2 emission rate (Sen. Bingaman CES proposal).

Figure 17: Comparison of different Macroeconomic model responses to CES policy and carbon cap in industrial sector for NUC case



electricity prices are rising in isolation from other fuels, creating incentives to move away from it. The scale effect reducing overall industrial output is minor.

Figure 17(b) displays the same effects for the economy-wide cap, and though the aggregate change in electric demand by 2050 is similar to the CES case, the decomposition is entirely different. In this case there is a significant impact on industrial output, and the intensity and capital substitution effects are greater. However, the most striking difference is the reversed direction of the fuel substitution effect. Whereas the CES policy penalizes electricity relative to other fuels, an economy-wide carbon cap rewards it. Still, the electricity price rises faster and higher in the cap case than in the CES, and the strengthened output, intensity, and capital (i.e. end-use efficiency) effects balance the substitution towards electricity, so that in both cases there is a roughly 3% decline in industrial electricity demand.

6. DISCUSSION AND CONCLUSIONS

In this paper, we have examined the implications of an electric sector CES with the new US-REGEN model, developed with emphasis on electric sector detail and macroeconomic interactions. The paper contributes to the understanding of this emerging policy option in the US while also demonstrating new methodological advances in the treatment of key physical and economic aspects of the electric sector in the context of dynamic optimization.

First, we examine how, and why, the generation and capacity mix under a CES could evolve differently depending on the costs and availability of alternative technologies. These results depict a wide range of possible futures for reducing carbon dioxide emissions from electricity generation. In the least constrained pathway, a balanced mix of renewables, nuclear, and natural gas emerges. With constraints on the expansion of either nuclear or inter-regional transmission, the other technology dominates, the latter undertaken to facilitate access to the highest quality renewable resources. With constraints on both, CCS is deployed. As the share of intermittent renewable technologies increases, the system must carry a larger capacity base, where the installed thermal capacity operating increasingly in back-up mode with a much lower capacity factor than in today's system. We note that only a model with sufficient spatial and temporal variability can reveal this insight.

Second, we examine the regional implications of alternative realizations of the CES. While the policy induces major changes in the national generation mix, the transformation in some regions can be particularly extreme. Moreover, the regional patterns are strongly dependent on technological constraints, as the competitive advantage (e.g. wind in the Midwest) shifts with the availability of interregional transmission or nuclear. Accordingly, we find that financial flows relating to the policy can be significant (e.g. $>$ \$10bn flowing into and out of individual regions by 2035), and that the direction and magnitude of the flows are very sensitive to the technology assumptions. The model's structure also provides insights into potential price effects at the regional level. In competitive pricing regions, the additional cost of credits when bundled into retail prices is offset by reductions in the wholesale market price, while under cost-of-service regulation, the change in price is based on the total net change in expenditure. Thus market structure can influence price impacts of the CES, with the key difference being that returns to existing generators are fixed in regulated regions, but are affected negatively (positively) for non-qualified (qualified) sources in competitive regions subject to wholesale markets.

Next, the analysis highlights the value of an expanded set of technological options, with a threefold increase in the 2050 CES credit price, and as much as a fivefold increase in total welfare impact between the HIC case and our other, more optimistic, technological scenarios. Notably, low natural gas prices do not have a large impact on CES credit prices, and in fact increase the welfare impact, due to the declining role gas generation can play as the CES target tightens. The cheaper the natural gas resource, the greater the opportunity cost of a policy that restricts it, even partially. We also observe that low natural gas prices relative to electricity will present an opportunity to the non-electric sector, allowing for increased potential for emissions leakage under the CES.

Finally, we explore the CES as compared with the 50% economy-wide cap cases specified in EMF 24. Although these cases are not purely comparable in terms of the overall level of mitigation, we find that a CES can produce a similar generation mix to that of a cap and trade scheme, electricity price impacts can be lower, and fundamentally different responses occur on the end-use side. In particular, the model's formulation of end-use energy demand demonstrates the offsetting effects of fuel substitution and enhanced efficiency through capital substitution. In a setting with the characteristics of the current parameterization of US-REGEN, i.e. with limited abatement opportunities outside the electricity sector, and limited scope for emissions leakage, a CES could be an attractive option for achieving emission reductions due to its lower impact on the price of both electric and non-electric fuels relative to the impact of a carbon price. However, it remains true in principle that economy-wide emissions pricing will be the most economically efficient means of achieving emissions reduction goals.

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APPENDIX

The following tables present, respectively, the definitions of the regions in US-REGEN, the costs and performance of new generation, and the elasticities of substitution used in the CGE model.

Table 3: US-REGEN Regional Definitions

Model Region	State(s) included
New England	Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut
New York	New York
Mid Atlantic	Pennsylvania, New Jersey, Maryland, Delaware
South Atlantic	Virginia, North Carolina, South Carolina
Florida	Florida
NE-Central-C (Competitive)	Ohio, Michigan, Illinois
NE-Central-R (Regulated)	West Virgina, Indiana, Wisconsin
SE-Central	Kentucky, Tennessee, Georgia, Alabama, Mississippi
NW-Central	Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas
SW-Central	Arkansas, Louisiana, Oklahoma
Texas	Texas
Mountain-N	Montana, Wyoming, Colorado
Mountain-S	New Mexico, Utah, Arizona, Nevada
Pacific	Washington, Oregon
California	California

Table 4 presents capital costs and heatrates for new generation by installation year and type.

Table 4: Time Varying New Technology Parameters

Technology	Installation Year	Capital Cost ($/kW)*	Heatrate (mmBTU / MWh)
Supercritical Pulverized Coal (with full environmental controls and without CCS)	2015	2530	8.749
	2030	2530	7.935
	2050 +	2530	7.582
IGCC Coal (with CCS) *(Not available until 2020)*	2020	4046	10.006
	2030	3729	8.726
	2050 +	3510	7.667
Natural Gas Combined Cycle (without CCS)	2015	1301	6.893
	2030	1301	6.319
	2050 +	1301	6.319
Natural Gas Combined Cycle (with CCS) *(Not available until 2020)*	2020	2041	7.403
	2030	1950	7.01
	2050 +	1835	6.89
Natural Gas Turbine (without CCS)	2015	815	11.01
	2030	815	10.19
	2050 +	815	9.75
Dedicated Biomass (based on a 50 MW direct fire plant)	2015	4404	12.875
	2030	4209	11.371
	2050 +	3962	10.662
Nuclear	2015	5475	10
	2030	5233	10
	2050 +	4926	10

(continued)

Table 4: Time Varying New Technology Parameters *(continued)*

Technology	Installation Year	Capital Cost ($/kW)*	Heatrate (mmBTU / MWh)
	2015	8775	
	2030	6746	
Solar Photovoltaic (Rooftop) *Less Optimistic*	2050 +	5670	N/A
	2015	2000	
	2030	2000	
Hydroelectric	2050 +	2000	N/A
	2015	4953	
	2030	4733	
Geothermal	2050 +	4456	N/A
	2015	2301	
	2030	1831	
Wind Power Onshore, *More Optimistic*	2050 +	1588	N/A
	2015	2301	
	2030	2199	
Wind Power Onshore, *Less Optimistic*	2050 +	2070	N/A
	2015	3556	
	2030	2829	
Wind Power Offshore, *More Optimistic*	2050 +	2453	N/A
	2015	3556	
	2030	3245	
Wind Power Offshore, *Less Optimistic*	2050 +	2873	N/A
	2015	3130	
Solar Photovoltaic (Central Station) *More*	2030	1951	
Optimistic	2050 +	1442	N/A
	2015	3766	
Solar Photovoltaic (Central Station) *Less*	2030	2933	
Optimistic	2050 +	2465	N/A
	2015	8775	
	2030	4487	
Solar Photovoltaic (Rooftop) *More Optimistic*	2050 +	3317	N/A
	2015	6218	
	2030	3875	
Concentrating Solar Power, *More Optimistic*	2050 +	2865	N/A
	2015	6218	
	2030	5220	
Concentrating Solar Power, *Less Optimistic*	2050 +	3904	N/A

* All costs are in constant 2009 dollars.

Table 5 lists fixed and variable operating and maintenance costs, and plant lifetimes of new generation.

Table 5: Non-time varying new technology parameters

Technology	Fixed O&M Costs ($/kW-year)*	Variable O&M Costs ($/MWh)*	Plant Lifetime
Supercritical Pulverized Coal (with full environmental controls and without CCS)	45.8	2	100
IGCC Coal (with CCS)	92.6	3.3	60
Natural Gas Combined Cycle (without CCS)	15.3	2.3	100
Natural Gas Combined Cycle (with CCS)	28.6	6.5	60
Natural Gas Turbine (without CCS)	14.3	4.3	100
Dedicated Biomass (based on a 50 MW direct fire plant)	60.1	5	60
Nuclear	105	1.7	80
Hydroelectric	67	0	100
Geothermal	67	8.6	100
Wind Power Onshore	37	0	25
Wind Power Offshore	98	0	25
Solar Photovoltaic (Central Station)	53	0	60
Solar Photovoltaic (Rooftop)	53	0	60
CSP (Solar Thermal)	72	0	60

* All costs are in constant 2009 dollars.

Note that operating costs are held constant over time and are assumed not to increase as a plant ages.

The key data for the Macroeconomic model are the elasticity parameters. The following table lists the elasticity parameters used by US-REGEN in its baseline scenario. These parameters are constant across time, except for σ_{ek}. In the baseline scenario, σ_{ek} starts at 0.05, and rises across time, asymptotically converging to an assumed long-run elasticity of 2.

Table 6: Summary of Elasticity Parameters

Elasticity Parameter	Description	Value	Sectors(s)
σ_c	Top level elasticity in residential demand	0.2	RES
	Top level elasticity in other end-use sectors	0.0	IND, COM, TRN
σ_b	Commercial Buildings	0.2	COM
σ_h	Housing Subcomponents	0.4	RES
	Heating: Electric vs. Non-electric	1.0	RES, COM
	Electricity-Gas	1.0	IND
σ_{nh}	Heating: Non-electric fuels	4.0	RES
σ_{nb}	Heating: Non-electric fuels	4.0	COM
σ_{kle}	Building vs. Energy	0.2	IND
	Capital Building Services	0.2	COM
σ_{ek}	Energy vs. Energy-using Capital	0.3	Energy Services
σ_{esub_nr}	Natural Resources		
σ_{va}	Labor-Capital	1.0	All Sectors
	Domestic-Foreign Imports	3.0	
	Inter-Regional Imports	5.0	

Assessing the Interactions among U.S. Climate Policy, Biomass Energy, and Agricultural Trade

Marshall A. Wise[†], Haewon C. McJeon*, Katherine V. Calvin*, Leon E. Clarke*, and Page Kyle**

ABSTRACT

Energy from biomass is potentially an important contributor to U.S. climate change mitigation efforts. However, large-scale implementation of bioenergy competes with other uses of land, including agriculture and forest production and terrestrial carbon storage in non-commercial lands. And with trade, bioenergy could mean greater reliance on imported energy. Based on EMF-24 policy specifications, this paper explores these dimensions of bioenergy's role in U.S. climate policy and the relationship to alternative measures for ameliorating the trade and land use consequences. It shows how widespread use of biomass in the U.S. could lead to imports; and it highlights that the relative stringency of domestic and international carbon mitigation policy will heavily influence the amount of imports. It demonstrates that limiting biomass imports could alter the balance of trade in other agricultural products. Finally, it shows that increasing efforts to protect both U.S. and international forests could also affect the balance of trade in other agricultural products.

Keywords: Biomass, Bioenergy, Land use, Climate mitigation, Agricultural trade

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1. INTRODUCTION

Energy from biomass (bioenergy) is potentially an important contributor to U.S. climate change mitigation efforts. Substituting biomass for fossil fuels in the energy system for uses such as generating electricity or creating liquid fuels could reduce CO_2 emissions. However, there are issues associated with large-scale reliance on bioenergy. One of the major issues is that biomass production competes with other uses of land, notably crop production and production of forest products. Because land is limited, expansion of land dedicated to biomass production would cause increased competition for land, potentially reducing the amount of land used for these other productive uses. In addition, expansion of cropland to produce biomass could reduce land in forest in general, both commercial and noncommercial, increasing land use change emissions as lands such as high-carbon forest is converted to lower-carbon cropland or land for biomass production. This issue of indirect land use emissions from biomass has been identified and studied by several authors, notably Fargione et al. (2008), Searchinger et al. (2008), Wise et al. (2009), and Havlik et al. (2011). The potential for policies that prohibit the expansion of cropland for biomass into forested lands and other non-commercial land types has been quantified by Melillo et al. (2009) and Popp et al.

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(2012). A comprehensive review of issues related to biomass production, technologies, use and its potential impacts on land use, greenhouse gas emissions, food production, and other issues of sustainability is provided by Chum et al. (2011).

An issue that has not been as widely studied is that a reliance on biomass could influence the balance of trade, foremost in biomass itself, but also potentially in other agricultural products. Domestic-focused studies of biomass production potential often assume, either explicitly or implicitly, that biomass production would not be done in a manner that affects food production and the U.S. position of being a major exporter of products (see, for example, DOE 2011). However, agricultural products are heavily traded internationally, and a large-scale commitment to domestic production of biomass at levels of demand associated with deep carbon emissions reduction could affect the U.S. agricultural trade position in biomass and food crops. On the other hand, the U.S. could also end up being a large-scale importer of biomass under an aggressive climate mitigation policy assuming its import is allowed.

Partly in response to these issues, the standard assumption to be used for the EMF-24 scenarios was that the U.S. could only use domestically-supplied biomass (see Fawcett et al., this volume). In this paper, we explore the implications of that assumption, as well as the impact of restrictions on land use change. For this study, we interpret the EMF-24 assumption as an explicit approach to limit the trade in biomass, ensuring that U.S. climate policy does not depend on biomass energy imports. To address the issue of emissions from land use change, we explore scenarios in which protections on forests are implemented to ensure that increased biomass production does not result in decreased forest land and associated land use change emissions.

This paper uses the EMF-24 scenarios as a starting point to explore the relationship between U.S. climate policy and trade in biomass and agriculture products. In particular, it focuses on four related questions. (1) How might U.S. climate policy influence trade in biomass? (2) How might U.S. climate policy influence trade in other agricultural goods? (3) How might efforts to reduce biomass imports influence trade in other agricultural products? (4) How might efforts to protect forests influence trade in other agricultural products? The GCAM integrated assessment model is used throughout the paper as the means to explore these questions.

We proceed to address these questions in two steps. In the first step, we focus on the impacts of the U.S. domestic climate policy on trade balances of biomass and other crops based entirely on the EMF-24 scenarios, but assuming no limits on biomass trade or on change in forested land. The wide-ranging technology scenarios of EMF-24 along with the various levels of U.S. climate policy in the EMF-24 scenario design provide an ideal vehicle to illustrate the mechanisms through which U.S. domestic climate policy might influence biomass and agricultural trade balances, and reveal the conditions that either increase or decrease such effects.

In the second step, we explore two policies, independently and together, intended to ameliorate some of the negative impacts of bioenergy. First, we model a biomass trade restriction policy where the U.S. can neither import nor export biomass. Second, we model a forest protection policy to represent a plausible reaction to biomass expansion into forest and land use change emissions, similar in a broad sense to a REDD policy (United Nations, 2008) though here applied as a strict global constraint. Both of these policies will have intended consequences, but it is important to also understand the potential unintended consequences they might have on trade in other agricultural products.

The remainder of the paper proceeds as follows. In Section 2, we briefly introduce the GCAM and provide links to additional documentation of its land use model component in particular. In Section 3 we provide the details of the design for the study. Section 4 and Section 5 provide the results of the analysis, first focusing on scenarios without trade or forest restrictions (Section 4) and then adding those in (Section 5). We close in Section 6 with final thoughts on the importance of understanding the interconnected nature of energy, land, and global market when designing U.S. climate policy.

2. GLOBAL CHANGE ASSESSMENT MODEL

The model we used to project each scenario into the future is the Global Change Assessment Model (GCAM). GCAM[1] (Clarke et al., 2007, Edmonds and Reilly, 1985) is an integrated assessment model that links a global energy-economy-agricultural-land-use model with a climate model of intermediate complexity. As part of GCAM's modeling of human activities and physical systems, GCAM tracks emissions and concentrations of the important greenhouse gases and short-lived species (including CO_2, CH_4, N_2O, NO_x, VOCs, CO, SO_2, BC, OC, HFCs, PFCs, and SF_6). GCAM is a market equilibrium model. It operates by solving for the set of prices in global and regional markets such that supplies and demands are in balance. At this model solution, all markets are in equilibrium. The version of GCAM used for this analysis was GCAM 3.0.[2,3]

GCAM subdivides the world into fourteen regions and operates from 2005 to 2095 in five-year increments. The agriculture and terrestrial system (Wise et al. 2011) further subdivides each of the GCAM's fourteen geopolitical regions into as many as eighteen sub-regions, based on the agro-ecological zones described by Monfreda et al. (2009). GCAM computes the supply and demand for primary energy forms (e.g., coal, natural gas, crude oil), secondary energy products (e.g., electricity, hydrogen, refined liquids), several agricultural products (e.g., corn, wheat, rice, beef, poultry, etc.). GCAM typically assumes global trade in fossil fuels and agricultural products, but can be operated with markets defined regionally. GCAM models three sources of lignocellulosic biomass supply: purpose grown crops that require dedicated land such as switchgrass and woody crops, residues from agriculture and forestry operations, and organic municipal solid-waste (Luckow et al. 2010). When we refer to *biomass* in this paper, we are referring to these lignocellulosic resources rather than energy derived from first generation resources such as starches and oil crops, although they are included in GCAM.

GCAM models several pathways for using lignocellulosic biomass in the energy system including production of electricity, liquid fuel, gas, and hydrogen. Biomass can also be consumed directly to provide end use heat. In the climate mitigation policies studied here, the use of biomass with carbon dioxide capture and storage (CCS) becomes an important source of electricity and liquid fuels in technology scenarios where CCS is available. GCAM includes the energy and cost required to collect, process by pelletizing or briquetting, and transport biomass for use in the energy system, with an approach and data from a study by Hamelinck et al. (2005). Luckow et al. (2010) describes in detail the data sources and values used in GCAM for biomass technology costs and energy conversion efficiencies. In addition, the greenhouse gas emissions that result from growing biomass and other crops, including those from fertilizer use, are also modeled in GCAM, with methods and data detailed by Kyle et al. (2011). With the noted exception of CO_2 emissions from

1. Note that GCAM was formerly known as MiniCAM.

2. It is not possible in this paper to fully document the GCAM model, so readers are encouraged to explore the GCAM documentation, and particularly the extensive documentation on the modeling of agriculture and land use, found at found at wiki.umd.edu/gcam.

3. For simplicity, we will refer to GCAM 3.0 simply as GCAM for the remainder of this paper.

Table 1: Scenario components

Baseline	
LowTech	all low tech (US23F)
BioRE	advanced bioenergy and renewables (US01F variant)
NucCCS	advanced nuclear and CCS (US21F)
Adv	all advanced supply tech (US15F)
AdvEE	all advanced supply tech and high end-use efficiency (US13F)
Emission constraints (indexed to 2005)	
Unconstrained (baseline)	
USA 50% abatement by 2050	
USA 80% abatement by 2050	
Other Constraints	
Trade	free trade of biomass, no constraints
Restrict	trade restriction on biomass
USA Protect	USA protected forest (non-commercial)
Global Protect	Global protected forest (non-commercial)

land use change, greenhouse gas emissions from growing and using biomass are included in the policy caps for the EMF-24 study (Fawcett et al., this volume).

All of the GCAM scenarios modeled in this paper share the same economic, demographic, natural resource and other critical assumptions described by Thomson et al. (2011)[4]. In particular, all scenarios assume a global population that grows until mid-century, peaks in 2065, and declines to approximately 9 billion between 2065 and 2100. Living standards continue to increase and technological improvements in the production of energy, energy-related services, and agricultural goods continue to occur throughout the century.

3. STUDY DESIGN

This study is based on the domestic policy and technology scenarios developed for EMF-24[5]. All of the scenarios explored in the study are summarized in Table 1.

3.1. Scenarios exploring the effect of technology and mitigation level

In the first portion of the analysis, we explore five of the core scenarios from the EMF-24 scenario set, which cover a wide range of future technology development pathways, as defined in Fawcett et al. (this volume). They include the extremes from the EMF-24 scenario set – the low technology development scenario (LowTech) and advanced technology development scenario (Adv) – along with the BioRE and NucCCS cases. In addition, we include a technology scenario that features advanced technology along with high end-use efficiency assumptions to represent the most

4. Note these are GCAM assumptions and not standardized to all models in EMF-24.
5. For more information on the EMF-24 scenario design, see Fawcett et al., this volume.

optimistic future in terms of energy technology development. The benefit of this spread of technology assumptions is that it captures a wide range of potential roles and deployment scales for bioenergy.

Along with these five technology sets, we overlay three different levels of domestic emission abatement policy, consistent with the EMF-24 design: unconstrained baseline, 50% abatement of greenhouse gas emissions (GHGs), not including CO_2 emissions from land use change, by 2050 and 80% abatement of GHGs, not including CO_2 emissions from land use change, by 2050. Again, consistent with the EMF-24 design, the rest of the world (RoW) is assumed to follow "muddling through" pathway, in which the more developed countries reduce emissions by 50% by 2050, less ambitious actions take place in some other countries, and no reductions in some fossil exporting countries. Note that this international policy regime holds irrespective of the U.S. policy regime. Note also that the international policy regime does not include the type of policy on carbon in land that was described in Wise et al. (2009); that is, there is no incentive in terms of an economic value placed on terrestrial carbon either to halt deforestation or encourage afforestation internationally.

3.2. Scenarios exploring the implications of restrictions on biomass trade and forest protection

In the second portion of the analysis, and to explore the implications of biomass trade and forest protection, we then select one focus case with advanced energy supply technologies (Adv) and stringent climate policy of 80% abatement by 2050. We then overlay different two biomass trade regimes and several degrees of forest protection.

Two trade regimes are considered to observe the effect of trade restrictions on biomass. The baseline "Trade" regime assumes free trade of biomass without any constraints. The alternative "Restrict" regime assumes no trade in biomass; that is, all domestic use of biomass must be supplied by domestic production.

Three levels of forest protection policies, including no protection, are considered. The baseline case assumes no particular forest protection policy is enforced, and biomass land and cropland are free to expand into the forest. The two protection cases assume that all non-commercial forest are protected and conversion to other land uses is not permitted. In the first of these, we assume only that U.S. forests are protected, while in the second, we assume global forest protection.

4. RESULTS: EFFECTS OF TECHNOLOGY AND POLICY STRINGENCY

4.1. Biomass in the context of the full energy system

Before discussing specific biomass and trade results, it is useful to see biomass use in these scenarios in the context of the entire energy system.[6] Figure 1 shows GCAM results for U.S. primary energy use in 2050 in each of the technology and mitigation scenarios. Biomass is a significant mitigation option across all of the technology scenarios, and it is especially important when there are few other options available (Low Tech and BioRE). When all mitigation options are constrained in the LowTech scenario, there is a large reduction in total energy use. In contrast when all major abatement technologies are present, the reduction in overall energy consumption is substantially smaller.

6. See Clarke et al. (this volume) for an overview of results from GCAM and the other participating models.

Figure 1: Year 2050 U.S. Primary Energy Consumption by technology and policy scenario (measured in electricity generated for nuclear, and non-biomass renewable)

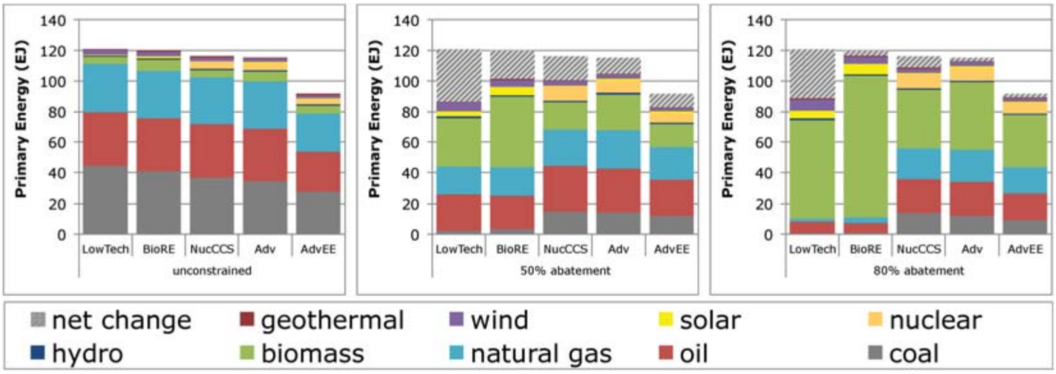
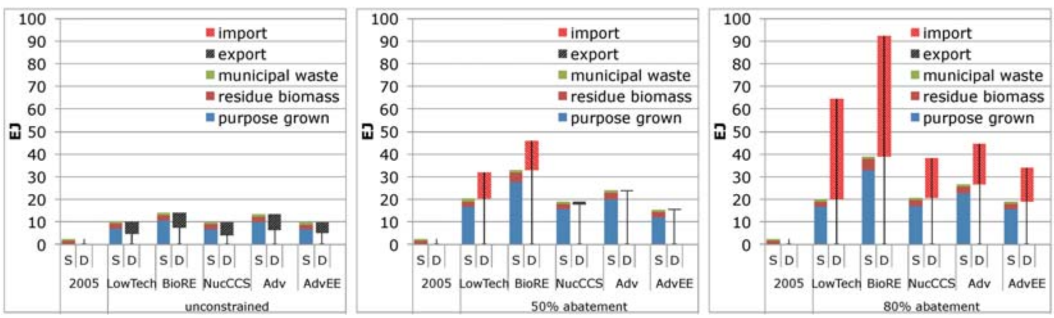


Figure 2: 2050 biomass production and trade by scenario. Emphasis on U.S. domestic climate policy and future technology development pathways. S, supply; D, demand.

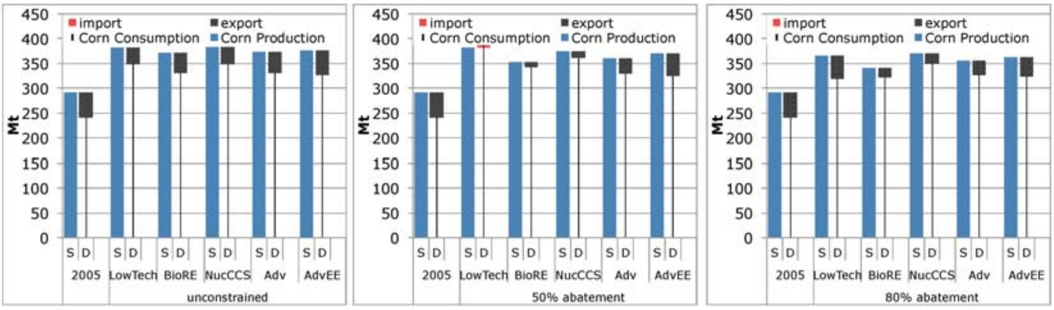


When advanced nuclear and CCS are available (NucCCS, Adv, and AdvEE), biomass use is moderate for the 50% abatement level, with nuclear and fossil fuel with CCS options playing a large role. However, at stringent abatement level (80%), all abatement technologies are fully utilized, including large increase in bioenergy use. In scenarios where CCS is available, most of the use of coal, gas, and biomass is done with CCS by 2050. When CCS is not available, the 80% abatement level leaves much less room for fossil fuel use.

4.2. Biomass production and trade

Figure 2 surveys the effects of policy and technology on the trade of biomass specifically. Across all technology assumptions, the U.S. becomes a net exporter of biomass by 2050 when there is no U.S. climate policy (the left panel in Figure 2). Because some other countries are taking on 50% reductions in greenhouse gas emissions as part of the international assumptions for EMF-24, these countries demand bioenergy as part of their low-emissions portfolio. Just as any other crop, the biomass is supplied from the agricultural regions where the relative profitability of growing is favorable compared to other uses of land, which includes the U.S. in these scenarios.

Figure 3: 2050 corn production and trade by scenario. S, supply; D, demand.



In contrast, when the U.S. also undertakes a climate policy, its biomass exports are reduced and, indeed, exports may turn to substantial imports. Climate policy in the U.S. increases the domestic demand for biomass. Higher demand pushes the biomass price higher, and hence the domestic biomass production is increased. However, although domestic biomass production responds in kind, it does not, in the cases explored here, respond sufficiently to maintain the same biomass trade balance as was the case without climate policy.

The degree to which the U.S. exports or imports biomass depends heavily on the stringency of the climate policy and the nature of the competing technological options for reducing emissions in the U.S. Not surprisingly, higher stringency of U.S. policy leads both to greater domestic biomass production and greater biomass imports. Ultimately, there are diminishing marginal returns on the production of domestic biomass (as well as on any land use), so that it cannot grow at the same rate as demand. Several of the 50% abatement cases include biomass imports by 2050; in all of the 80% abatement cases the U.S. is a heavy importer of biomass.

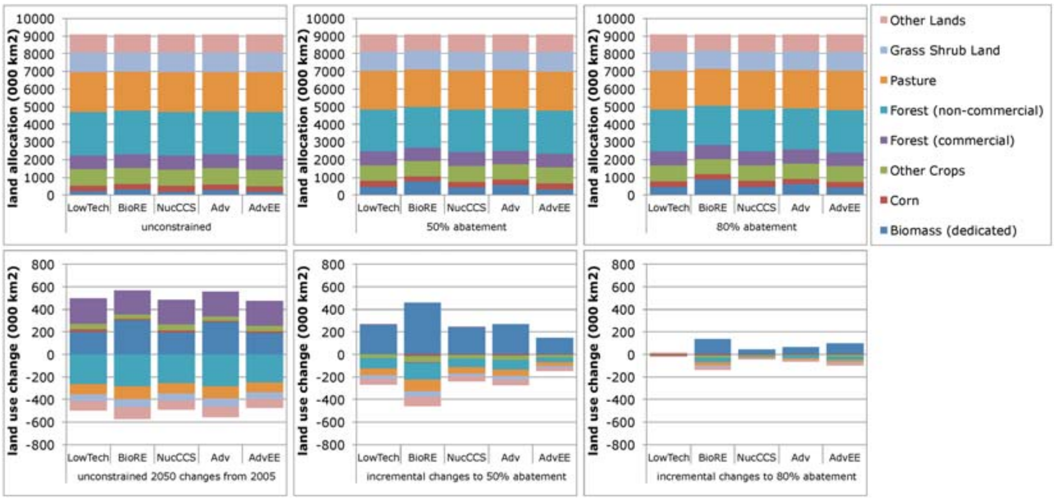
The first order effect of technology assumptions on the biomass trade balance is essentially just to alter the level of biomass demand, all else equal. When other low carbon energy options, such as nuclear or CCS, are readily available, the demand for biomass is lower. Hence, at a 50% abatement level, the U.S. does not need to import biomass when nuclear and CCS are both available. On the other hand, biomass imports are largest when the pressure to use biomass is increased due to limited availability of other technology options (LowTech) or when global biomass supply is plentiful and advanced bioenergy technologies exist, favoring the use of bioenergy as a major abatement option (BioRE).

4.3. Corn production and trade

Dedicated lignocellulosic biomass crops such as switchgrass ultimately compete with other agricultural crops for land. Hence, if biomass demands and production are altered through climate policy, the expectation is that there should be effects on the other crops against which biomass competes. Here we focus our results discussion on corn as emblematic of U.S. crop production and exports. (Figure 3).

In general, the influence of U.S. climate policy on corn production and exports is relatively modest. The U.S. was a heavy exporter of corn in 2005 and remains a heavy exporter in 2050 across the GCAM scenarios assuming no climate policy in the U.S. (the left panel in Figure 3). There are some variations in domestic corn production and in the amount of corn exports, but the general tendency to export is robust across different technology scenarios.

Figure 4: U.S. 2050 land allocation (upper) and incremental land use change relative to the less stringent scenario (lower) by scenario.



Continuation of corn exports is preserved in all but one abatement scenario. The sole exception is the LowTech 50% abatement scenario where the U.S. becomes a slight net importer of corn. In the absence of other major abatement options (LowTech), the conventional corn ethanol becomes one of the few remaining abatement options for the U.S., and this contributes to the U.S. to become a net importer of corn.

In other cases, as the abatement level becomes more stringent, overall corn production is decreased due to increased land area needed to produce lignocellulosic biomass crops. The combined effect on corn net exports is ambiguous. It depends on the relative magnitude of reduction in production and consumption. The magnitude of reduction in production, in turn, depends on the comparative advantage of corn and biomass production in the U.S. and in the rest of the world. And the magnitude of reduction in consumption depends on the combined elasticity of the demand response of corn consumption for feed, food, ethanol, and other uses. Among the scenarios considered, we generally observe a decreasing amount of net exports of corn with respect to abatement level. However, the effect is rarely strong enough to make the U.S. a net importer of corn.

4.4. Land allocation and land use change

Ultimately, changes in U.S. production of corn and biomass are determined by the amount of land devoted to each, as well as to other crops or uses of land (Figure 4). Without a domestic climate policy (the left panels in Figure 4), the U.S. devotes more land to biomass, to corn, to other crops, and to commercial forest land. As the world economies and populations continue to grow, there is more demand for the agricultural and forest products, as well as an increased demand for bioenergy in those countries undertaking climate mitigation. This will tend both to increase the demand for bioenergy in general, and also supplant other productive uses of land in those countries that are undertaking climate mitigation. As a result of increasing production of these tradable products, the U.S. decreases the amount of land in unmanaged uses (non-commercial forest, grass and shrubland, other lands) as well as pasture lands not used for grazing.

The introduction of a constraint on emissions in the U.S. further increases the demand for bioenergy, and therefore increases the biomass production in the U.S. (the middle and right panels of Figure 4). The incremental change in land use (the bottom middle and right panels of Figure 4) is almost entirely due to an increase in biomass production over the reference or no-policy case. It is interesting to note that the incremental effect of the 50% reduction scenario (the bottom middle panel of Figure 4) is substantially larger than the incremental effect of moving from a 50% reduction to an 80% reduction scenario (the bottom right panel of Figure 4), indicating diminishing marginal returns to expansion of cropland for biomass and other crops. After meeting the first 50% abatement constraint, it requires substantially larger change in profitability to expand into the remaining lands.

The magnitude of this substitution depends highly on the technology development pathways. As noted above, all else equal, the availability of other advanced technologies reduces the magnitude of substitution (e.g. NucCCS and AdvEE). On the other hand, the availability of advanced biomass technology increases the magnitude (e.g. BioRE).

5. RESULTS: IMPLICATIONS OF FOREST PROTECTION AND BIOMASS TRADE RESTRICTIONS

In the previous section we observed two important potential influences of U.S. domestic climate policy related to biomass production and consumption. One issue was an increased reliance on imported biomass. A possible remedy for these issues is to restrict biomass imports; in other words, all biomass used for abatement in the U.S. energy sector must come from a domestic source. Such policy could be proposed based on inability to control indirect emissions outside the U.S. jurisdiction, or based on a desire to limit energy imports. Another, and related influence of U.S. policy is deforestation from land use change. Deforestation results in CO_2 emissions from land use change, at least partially offsetting the original purpose of climate policy.

To address these two concerns, we introduce two new sets of constraints on the scenarios. The first of this is the introduction of an alternative trade regime where the trade of biomass is restricted to only allow domestic supply in the U.S. (“restrict”). In contrast, the baseline assumption of GCAM is that biomass is grown where its relative profitability is favorable, and it is traded freely across national boundaries (“trade”). The second constraint is a forest protection policy, in which all non-commercial forested land in the base year 2005 must be kept as forests indefinitely. There are two scopes of the forest protection policy: “USA protect” and “Global protect”, as well as a baseline “not protect” case.

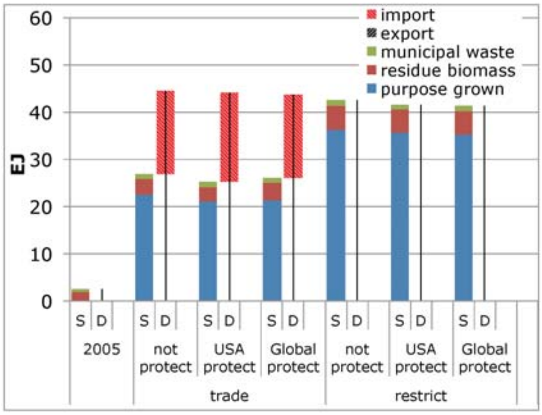
To maintain a reasonable scope for this additional analysis, we focus here only on a single scenario: the advanced technology scenario with 80% abatement constraint. Using this scenario, we overlay the two additional sets of constraints (see Table 1). All six combinations of trade regimes and forest policies are compared in this section.

5.1. Biomass production and trade

The immediate effects of the additional constraints are first observed in the biomass market (Figure 5). Trivially, biomass trade restrictions forces net imports of biomass to be zero. The market equilibrium effect of this policy is two-fold: domestic biomass supply substantially increases, and domestic demand slightly decreases.

The balancing of the domestic biomass market relies heavily on the large increase in supply, not on decrease in demand. Given the availability of suitable arable lands in the U.S. for

Figure 5: 2050 biomass production and trade under 80% abatement scenarios with advanced technology. Emphasis on land use policies and biomass trade restrictions. S, supply; D, demand.



growing additional biomass and the ability to import the foregone production of other crops from overseas, the long-run supply of domestic biomass can be highly flexible (also see, Figure 8)

On the other hand, the small decrease in demand represents the level of stringency of the abatement constraint. At the 80% abatement level, each and every abatement option is valuable so that biomass energy will be used even at a high price. This effect is better demonstrated with the market price effect in Figure 7.

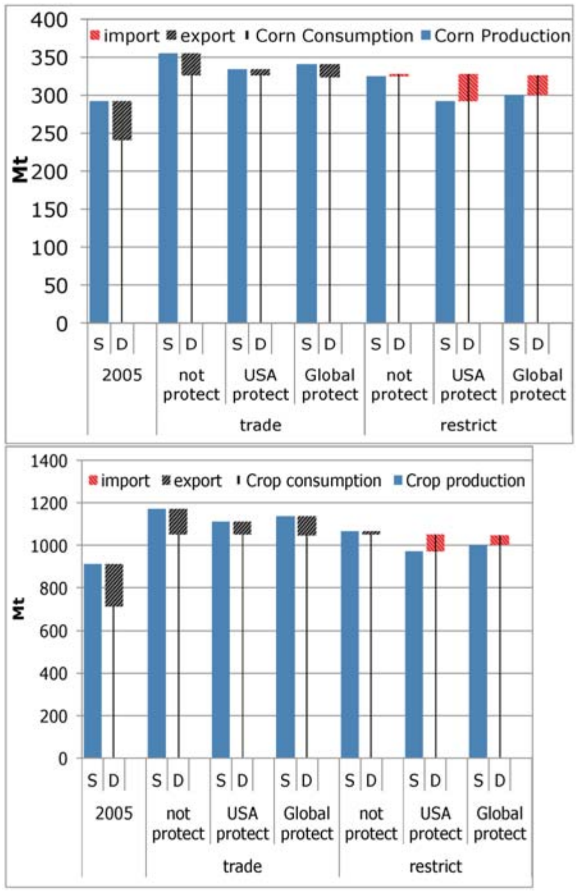
The effect of forest protection policies on biomass trade is consistent with intuition (see Figure 5). Under the free trade regime, protecting domestic forest lands results in higher pressure in current agricultural land that results in reduced production of all crops including biomass, relative to reference case future levels. The reduced domestic production is made up by a combination of increased imports from the regions without forest protection policy and decreased consumption. When the forest protection is applied globally, the competition for agricultural land becomes stronger in all regions, and as a result the biomass import is reduced. The decrease in global production is made up by a combination of increased U.S. domestic production and decreased consumption.

A similar effect due to forest protection is observed under the restricted biomass trade policy. Protecting domestic forest results in reduced future production of all crops, including biomass, relative to reference case values. The reduced domestic biomass production is only matched by reduced domestic consumption, since biomass imports are restricted. When the forest protection is applied globally, the pressure on agricultural land becomes stronger in all regions, and since biomass import is not an option, this pressure on land competition results in further reduced domestic production and consumption of biomass.

5.2. Corn and other crop production and trade

The constraints on imports and forest protection policies cause ripple effects to other crops that compete with biomass. In addition to using corn to illustrate these effects, we also present results for total non-biomass crop production (Figure 6). Recall that at the 80% abatement constraint, all technology scenarios showed a decrease in U.S. corn exports, although it still maintained a net-

Figure 6: 2050 corn (top panel) and total crop (bottom panel) production and trade under 80% abatement scenarios with advanced technology. Emphasis on land use policies and biomass trade restrictions. S, supply; D, demand.

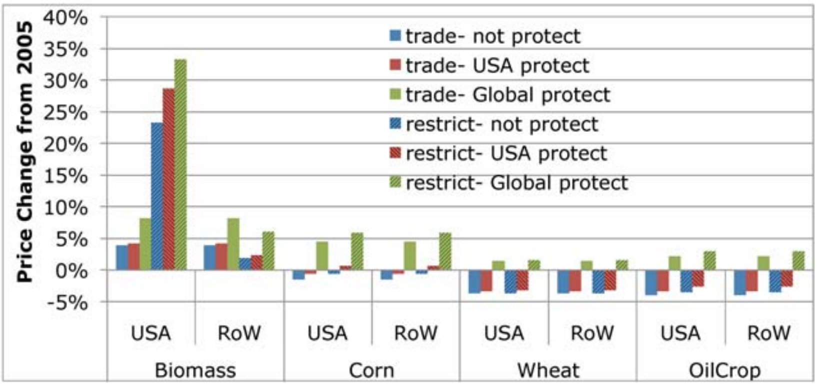


exporter status. This is still true – though at an ever smaller size of net exports – under any forest protection policies as long as biomass is freely traded. However, notice that under the restricted biomass trade regime, the U.S. becomes a net importer of corn.

The biomass trade restriction increases the pressure to grow more biomass domestically. In order to do so, portions of other cropland are converted for biomass production. As a result, domestic production of corn is reduced as we enforce biomass trade restriction. Biomass production competes against all crops for land use, and a similar effect is seen on other crops as well. In order to fulfill the domestic demand, some corn, as well as some amount of other crops, must be imported. Depending on the share of converted land area and comparative advantage, the net export of a crop may be merely reduced or net import of a crop may be further increased, but in this specific combination of abatement level and technology, the corn trade balance coincidentally turns from net export to net import. However, the direction of the effects of biomass trade restriction on *non-restricted* crop trade balances is unambiguously negative.

Domestic forest protection policies further increase competition for agricultural land use, and result in a smaller domestic corn production. The effect is similar for both trade regimes. With

Figure 7: 2050 crop price change under 80% abatement scenarios with advanced technology. Emphasis on land use policies and biomass trade restrictions. RoW, rest of the world.



little change in domestic demand, the differences in production directly results in reduced net export under free trade regime and increased net import under restricted biomass trade regime. When the forest protection is applied globally, this effect is reversed. As the land available for crop production is reduced in the rest of the world, some supply that provided imports of crops from the rest of the world is no longer available, resulting in a higher domestic supply of crops, including corn.

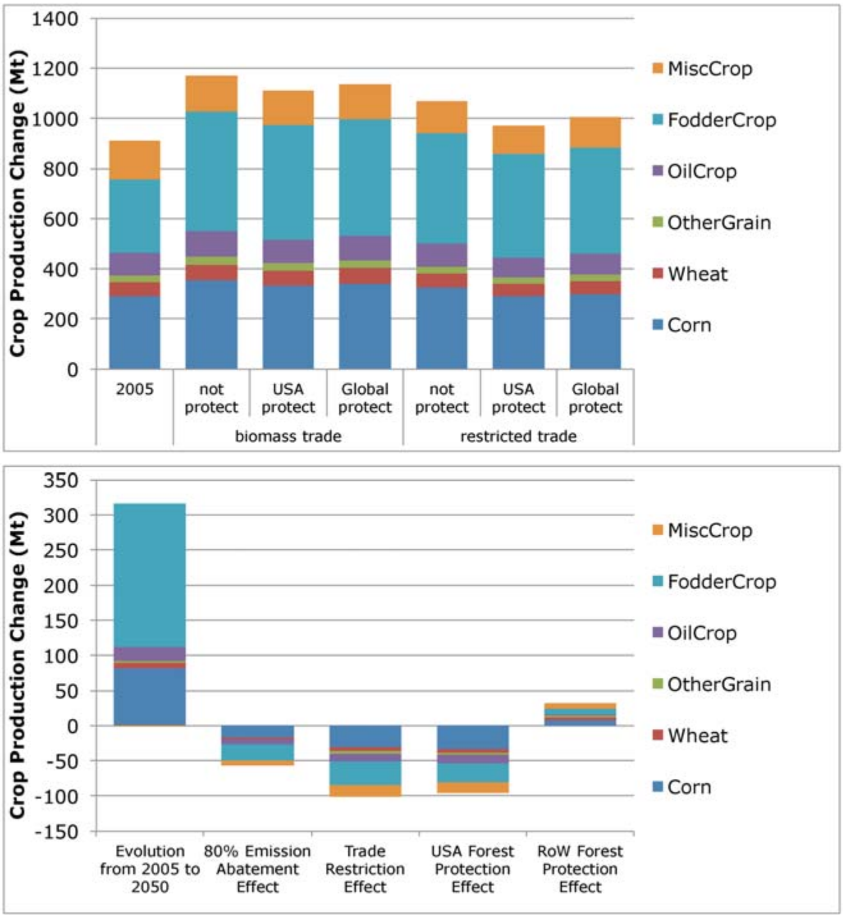
5.3. Crop prices

The crop price changes shown in Figure 7 help illustrate the dynamics of pressures on land competition from the biomass trade and forest protection policies. A trade restriction, by definition, creates two different markets with two different prices for the same good (here, biomass). With the stringent abatement constraint, the U.S. would have been a net importer of biomass in the absence of a trade restriction. But as the trade restriction is introduced, the price of the U.S. biomass increases to provide incentives for domestic growers to switch to biomass production. In an opposite effect, the introduction of the trade restriction leaves the rest of the world with more biomass, which then drives down the market-clearing price outside of the U.S.

Because we assumed free global trade of all of the crops shown, all the other crops have the same price for the U.S. and the rest of the world. The trade restriction reduces economic efficiency in the world biomass markets. This inefficiency results in a large increase in price for the region and crop directly targeted for trade restriction (USA biomass), as well as smaller increases in global prices for all other freely traded crops. The differential increase in crop price makes other crops relatively less profitable to biomass in the U.S., and increased comparative advantages of other crops prevail in the rest of the world to produce more of them and either export them to the U.S. or substitute what used to be imported from the U.S. to domestic production. The combined effect is decreased net exports and increased net imports of globally traded crops in the U.S.

Forest protection policies show differential impacts on crop prices between traded crops and non-traded biomass crop. The U.S. domestic forest protection mainly affects the non-traded biomass, and shows a smaller impact on the other crops. When the competition for land is increased, biomass, the only crop that cannot be supplied from elsewhere, faces a large increase in price in

Figure 8: 2050 crop production under 80% abatement scenarios with advanced technology. Emphasis on land use policies and biomass trade restrictions.



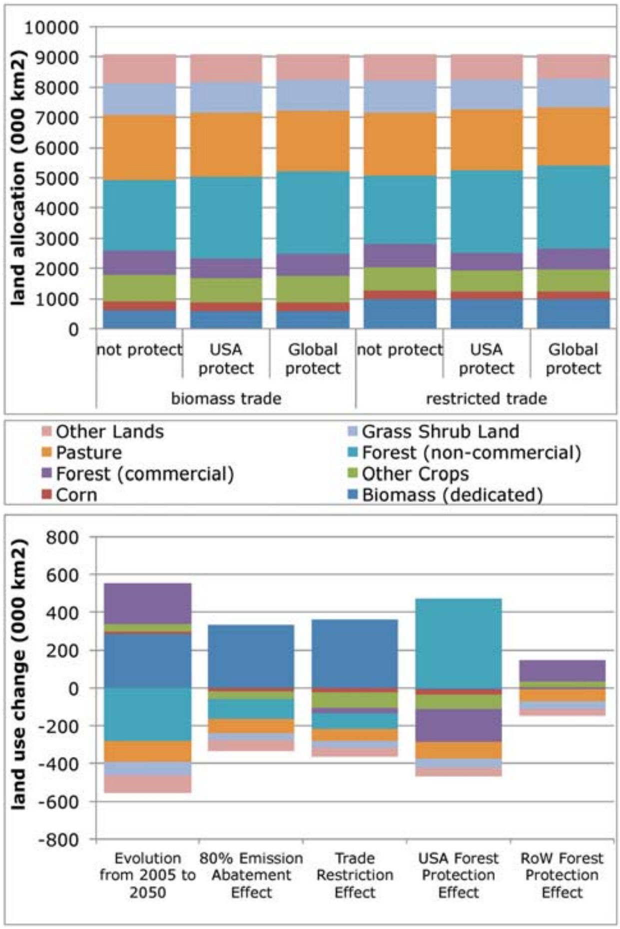
the U.S. However, when the forest protection policy is applied globally, the increased pressure on agricultural land everywhere increases all crop prices.

5.4. Other crop production and land allocation

All other major crops see the same effect as corn (Figure 8). Trade restrictions on biomass reduce production of all other crops in order to produce more biomass domestically. This effect goes beyond the croplands. All arable land types, including forest, pasture, grassland, shrubland, and so on, are decreased to provide sufficient land for increased domestic biomass production (Figure 9).

Domestic forest protection further reduces production of all other crops in order to maintain protected forest areas. The replacement effect is limited for biomass land, which is both highly restricted and valuable. Instead, the replacement is heavily focused on commercial forest and pasture, where the land has become relatively less profitable. And finally the rest of the world's implementation of a forest protection policy induces the U.S. to increase crop production to make up

Figure 9: 2050 land allocation and land use change under 80% abatement scenarios with advanced technology. Emphasis on land use policies and biomass trade restrictions.



for some of the decreased production outside of the U.S. Throughout the incremental additions of forest constraints, pasture, grass and shrub lands, and other non-commercial lands are incrementally replaced by croplands for food, biomass, and other agricultural products.

6. CONCLUSION AND DISCUSSION

This paper uses the GCAM integrated assessment model to explore the interconnected effects of biomass energy with climate policy, land use, energy, and agricultural trade. In the first part of the analysis, we observed the impacts of U.S. climate policy on agricultural trade. Implementing a domestic emission constraint increases the consumption for biomass in the U.S. All else equal, increased domestic consumption results in a net increase in biomass imports (or a net decrease in biomass exports). The precise magnitude of biomass imports depends on a number of factors, including other available abatement technologies, the stringency of domestic emission constraints, and the relative stringency of climate policies in other parts of the world.

In the second part of the analysis, we focused on one specific technology scenario and a stringent 80% abatement policy to further explore the different aspects of the issue. We modeled a biomass import restriction to address the concerns of energy imports and indirect land use change emissions. All else equal, high domestic demand for biomass coupled with the trade restrictions results in higher domestic production of biomass. When more land is used for biomass production, the domestic production of other crops decreases, which is partially offset by increased imports. A policy proposal of trade restrictions on biomass should take the indirect impact on food imports and exports into consideration.

We also explored a forest protection policy, much like that studied by Popp et al. (2012) as an additional, more direct means to address the concerns regarding land use change emissions resulting from biomass production. All else equal, a domestic forest protection policy coupled with high biomass demand puts high pressure on arable land. Physical limits on domestic cropland expansion results in further increases in crop imports. In some of the most stringent cases analyzed in this research, the U.S. becomes a net corn importer. The increased corn production in the rest of the world would also cause changes in land use patterns and corresponding changes in emissions. We included another scenario with a globally coordinated forest protection policy designed to address the issue of land use change emissions merely shifting from one country to another. In this scenario, the pressure on agricultural land increases globally and the U.S. crop imports are decreased.

Our findings from this analysis do not substantively contradict intuition. However, the value-added in building a formal model to test our hypotheses is in providing a detailed understanding of the mechanism in which our hypotheses materialize. While these scenarios are intentionally developed to illustrate the extreme in the broad range of plausible policy environments, it is worth noting the unintended consequences quantified here. The modeling results do not show or imply that these impacts on biomass and food crop trade themselves are negative, but instead that they may exist.

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U.S. CO_2 Mitigation in a Global Context: Welfare, Trade and Land Use

Ronald D. Sands, Katja Schumacher**, and Hannah Förster****

ABSTRACT

We describe carbon dioxide mitigation scenarios specified by the Energy Modeling Forum study (EMF-24) "U.S. Technology Transitions under Alternative Climate Policies," using a global computable general equilibrium model that simulates world energy and agricultural systems through 2050. One set of scenarios covers variation across five major technology groups: end-use technology, carbon dioxide capture and storage, nuclear electricity generation, wind and solar power, and bioenergy. Other scenarios cover variation across policies. Policies such as a renewable portfolio standard for electricity generation or a clean electricity standard have the potential for significant emissions reductions, but at a greater cost than a cap-and-trade scenario with the same reduction in emissions. Cap-and-trade scenarios resulted in carbon dioxide leakage rates of 11 to 20 percent depending on the stringency of the targets. Oil-exporting regions without a mitigation policy may still have significant welfare losses when other world regions reduce emissions.

Keywords: Carbon dioxide, Climate policy, Carbon leakage, Land use, Bioenergy

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1. INTRODUCTION

In this paper we describe carbon dioxide (CO_2) reference and mitigation scenarios specified by the Energy Modeling Forum study (EMF-24) "U.S. Technology Transitions under Alternative Climate Policies," using the Future Agricultural Resources Model (FARM), a global computable general equilibrium (CGE) model that simulates world energy and agricultural systems in five-year time steps starting in year 2004. EMF-24 guidance specifies 42 scenarios designed to cover a range of technology and policy options for greenhouse gas mitigation in the United States through year 2050.

Using the GTAP 7 data set as a benchmark social accounting matrix in 2004, we partition the world into 15 regions with the United States as a single region. Taking advantage of a balanced approach to agriculture and energy in a global economic framework, we address the following questions using the FARM model. How does a CO_2 mitigation strategy in the U.S. affect economic

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The views expressed are those of the authors and should not be attributed to the Economic Research Service, the U.S. Department of Agriculture, or the Öko-Institut.

welfare? How does a CO_2 mitigation strategy in the U.S. affect land use in the U.S.? Are there significant spillover effects through international trade in economic welfare or land use?

Technology assumptions in all scenarios apply to all 15 world regions. Cap-and-trade mitigation scenarios apply to the United States, the European Union, and other member countries of the Organization for Economic Cooperation and Development (OECD), but not to developing countries. This allows a calculation of carbon leakage through international trade. Other CO_2 mitigation scenarios, applied only to the United States, include a renewable portfolio standard (RPS) for electricity generation, a clean electricity standard (CES), and transportation regulations to improve fuel efficiency. For each mitigation scenario and world region, change in consumer welfare is computed as equivalent variation relative to the corresponding reference scenario.

Bio-electricity is the primary link between energy and agricultural systems in these FARM scenarios. Bio-electricity is present in all reference scenarios as combustion of solid biomass, or co-firing solid biomass with coal, to generate electricity. Bio-electricity grows rapidly in the U.S. in most mitigation scenarios, with the quantity of bio-electricity depending on the CO_2 price, the price of certificates in a renewable portfolio standard, the rate of improvement of biomass crop yield over time, and the availability of other mitigation technologies.

The presence or absence of CO_2 capture and storage (CCS) distinguishes many of the technology scenarios. If available, CCS can be used with any electricity generating technology that emits CO_2, provided the CO_2 price is high enough to cover the cost of CCS. Bio-electricity combined with CCS is a special case, with electricity and net carbon sequestration as joint products.[1]

FARM is one of ten models participating in EMF-24 and each model has its own strengths and limitations. The primary strengths of FARM within EMF-24 are global coverage and a balanced approach to energy and agricultural systems within a CGE model. This allows calculation of carbon leakage, changes in welfare as equivalent variation, and changes in land use. The EMF-24 study is unique in its analysis of a wide range of alternative U.S. climate policies across varied technology futures. A particular strength of EMF-24 is an analysis of the tradeoff between emissions reductions and welfare cost for various climate policies, especially policies not on the efficient frontier.

Carbon leakage has been addressed in a theoretical context by Hoel (1991) and in a recent multi-model study organized by EMF (Böhringer, Balistreri and Rutherford, 2012). Other studies have addressed the greenhouse gas implications of biofuel targets (e.g. Timilsina and Mevel, 2013; Beckman, Jones and Sands, 2011). However, the studies most closely related to EMF-24 are a concurrent study with global greenhouse gas concentration targets (EMF-27) and previous EMF studies (e.g. Clarke and Weyant, 2009).

We provide a description of EMF-24 scenarios in Section 2 of this paper, including specific assumptions used in FARM implementation of scenarios. In Section 3 we describe the economic framework of the FARM model, including benchmark data and functional form of production and demand systems. Selected output on CO_2 prices and emissions across EMF-24 scenarios is provided in Section 4. In Section 5 we use welfare calculations from the cap-and-trade scenarios to display the tradeoff between emissions reductions and welfare cost. Emissions leakage to countries outside OECD and the European Union, and welfare impacts on other countries, are the topics of Section 6. The main topic of Section 7 is land use change in response to CO_2 mitigation scenarios.

2. OVERVIEW OF SCENARIOS

Out of 42 scenarios in the EMF-24 study, eight are reference scenarios with varying assumptions across five major technology groups: end-use technology, CO_2 capture and storage,

1. Sands et al. (2014) provide a detailed description of bio-electricity combined with CCS in the FARM model.

Table 1: EMF-24 scenario matrix

Technology Dimension								
End Use	High	Low	High	High	High	High	Low	Low
CCS	High	High	Low	High	High	Low	High	Low
Nuclear	High	High	High	Low	High	Low	High	Low
Wind and Solar	High	High	High	High	Low	High	Low	Low
Bioenergy	High	High	High	High	Low	High	Low	Low
Policy Dimension								
Reference	US13	US15	US17	US19	US02	US01	US21	US23
50% Cap-and-Trade	US14	US16	US18	US20	US04	US03	US22	US24
80% Cap-and-Trade					US26	US25		
Electricity (RPS + Coal) + Transportation					US06	US05		
Electricity (RPS + Coal) + Transportation + 50% Cap-and-Trade					US08	US07		
Transportation					US10	US09		
Elelctricity (RPS + Coal)					US12	US11		
Electricity (CES + Coal)					US28	US27		

Notes: Not shown are 14 cap-and-trade scenarios, based on US01 and US02 reference cases, to trace out efficient frontiers for comparison to other policy scenarios. The additional cap-and-trade scenarios have 2050 reduction targets of 0%, 10%, 20%, 30%, 40%, 60% and 70% below 2005 emissions.

nuclear electricity generation, wind and solar power, and bioenergy. All of the remaining scenarios are mitigation scenarios. Eighteen mitigation scenarios are economy-wide cap-and-trade with varying degrees of stringency using either US01 or US02 as the corresponding reference scenarios (Table 1). Another six mitigation scenarios are cap-and-trade using the six other reference scenarios. The remaining mitigation scenarios are targeted to transportation and electricity generation. Scenarios US13 and US14 apply optimistic assumptions to all technologies ("all good"); scenarios US23 and US24 use pessimistic assumptions ("all bad").

Table 2 provides specifics of the way technologies are represented in the FARM model. In the case of end-use energy technologies, the difference between low and high efficiency is somewhat less than EMF-24 guidance.[2] In the cases of wind, solar, and bio-electricity, specifics of technical change over time were left as modeler's choice. Table 3 provides FARM specifics for EMF-24 mitigation policies.

3. ECONOMIC FRAMEWORK

The computational framework for all scenarios is the Future Agricultural Resources Model. The first version of FARM was constructed in the early 1990s by Roy Darwin of the Economic Research Service, and was used for analysis of climate impacts on global agriculture. Construction of a new version of FARM began in 2010 with model development driven by requirements of two

2. End-use energy efficiency is endogenous in a CGE model, but is influenced by coefficients of the economic production function and relative prices of inputs to production.

Table 2: FARM technology characteristics for the United States

	High Tech	Low Tech
End Use	Optimistic assumptions on rates of technical change for end-use energy technologies.	Final energy consumption in 2050 (US15) is 12% greater than High Tech reference scenario (US13). CO_2 emissions are 16% greater.
CO_2 Capture and Storage (CCS)	CCS is available at a break-even cost of $50 per tCO_2 for all electricity generating technologies that emit CO_2, including bio-electricity.	No implementation of CCS.
Nuclear	Nuclear is fully available.	Nuclear is phased out after 2010.
Wind and Solar Energy	Capital cost per kW declines by 2.5% per year.	Capital cost per kW declines by 1% per year.
Bioenergy	Biomass crop yield increases by 1% per year.	Biomass crop yield is constant over time.

Notes: For the United States, the difference between High Tech and Low Tech end-use energy consumption is smaller than EMF-24 guidance of 20%. Low tech end-use assumptions vary among other world regions in FARM, but show patterns similar to the United States. All other technology assumptions apply to all other world FARM regions in the same way as the United States.

international model-comparison activities: the Stanford Energy Modeling Forum and the Agricultural Model Inter-comparison and Improvement Project (AgMIP). This required a capability to simulate global energy and agricultural systems through at least 2050, with scenarios that vary across technology availability and policy environment. Bioenergy provides an interface between agricultural and energy systems in some scenarios, especially greenhouse gas mitigation scenarios.[3]

New tools and data have become available since the first version of FARM was constructed, most notably global social accounting matrices provided by the Global Trade Analysis Project (GTAP) at Purdue University (Hertel, 1997), and tools for using GTAP data in the GAMS[4] programming language (Rutherford, 2010). Therefore, development of the new FARM model did not start from scratch: the starting point is software provided by Rutherford. This software provides a comparative-static global CGE model fully compatible with GTAP 7 social accounts with bilateral trade between world regions.

The FARM model has been extended in many ways beyond the model in Rutherford (2010): conversion from comparative-static to a dynamic-recursive framework with five-year time steps, conversion of the consumer demand system to the Linear Expenditure System (LES), allowing for joint products in production functions, introduction of land classes for agricultural and forestry production, and introduction of electricity generating technologies.

Data required to benchmark a global computable equilibrium model are substantial: we benchmark FARM to the GTAP 7 data set, which has a base year of 2004. The central component of GTAP 7 is a set of balanced global social accounts for 112 world regions, embedded input-output tables for 57 commodities and five primary factors of production, and bilateral trade between regions. Social accounts are in values (2004 U.S. dollars) but lack quantity information. GTAP provides additional data tables on energy quantities, land use, and production of major field crops

3. We use the term “bioenergy” to be any energy carrier produced from biomass. In this paper, “bio-electricity” refers to electricity generated by combusting solid biomass.

4. General Algebraic Modeling System

Table 3: FARM policy assumptions for the United States

Policy	Description
Reference	No climate policy.
50% Cap-and-Trade	A national policy that requires CO_2 emissions in 2050 to be 50% less than CO_2 emissions in 2005. CO_2 emissions targets for other years decline linearly from 2012 emissions to the 2050 target. Banking and borrowing are not allowed.
Renewable Portfolio Standard (RPS)	The RPS applies only to the electricity sector. Renewable energy includes hydroelectric power, wind, solar, and bio-electricity. Targets are expressed as the fraction of electricity generated by renewables: 20% by 2020, 30% by 2030, 40% by 2040, and 50% by 2050. Banking and borrowing are not allowed.
Clean Electricity Standard (CES)	This policy is similar to the RPS, but also includes nuclear power, fossil electricity with CCS (credited at 90%), and natural gas (credited at 50%). Targets are expressed as the fraction of electricity generated: 50% by 2020, 60% by 2025, 70% by 2030, 80% by 2035, 90% by 2040, and 90% in later years. Banking and borrowing are not allowed.
New Coal[a]	All new coal-fired electricity generating plants use CCS with 95% capture efficiency.
Transportation Regulatory Policy	Linear reduction in land transportation CO_2 emissions from 2012 levels to 55% below 2010 levels in 2050. Banking and borrowing are not allowed.

Notes: Cap-and-trade assumptions apply to four other FARM regions: Western EU, Eastern EU, Japan, and other OECD90. None of the other policies apply to regions outside the United States.
[a] This policy was difficult to implement when combined with cap-and-trade: both policies rely on a CO_2 price in FARM, but we have a single CO_2 price in the United States.

Table 4: FARM regions for EMF-24 (15 regions)

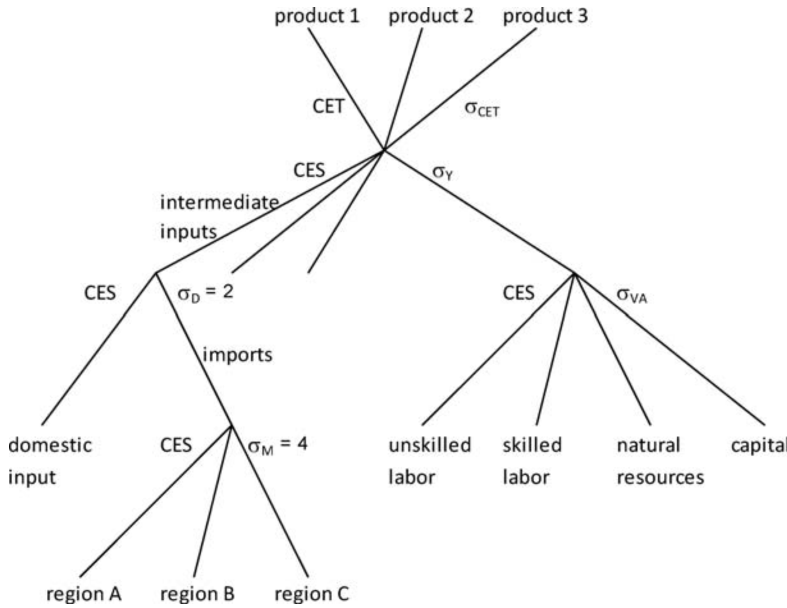
Region ID	Description
usa	United States
japan	Japan
westEU	Western European Union (15 countries)
eastEU	Eastern European Union (12 countries)
othOECD90	other OECD countries in 1990
russia	Russian Federation
othREF	other former Soviet Union and reforming economies
china	China
india	India
indonesia	Indonesia
othAsia	other Asia
midEastNAf	Middle East and North Africa
subSahAf	Sub-Saharan Africa
brazil	Brazil
othLatAmer	other Latin America

Note: Regional IDs are used in figures later in this paper.

in 2004. We aggregate GTAP commodities from 57 to 38 production sectors, and world regions from 112 to 15 for computational tractability. All relevant GTAP detail on agricultural and energy products was retained during aggregation. We operate FARM with five-year time steps from 2004 through 2054.

GTAP value and energy quantity data allow simulation over time of five energy carriers: coal, crude oil, natural gas, refined coal and petroleum products, and electricity. Further data processing expands the number of production sectors: the single electricity production sector in GTAP

Figure 1: Generic nesting structure for production functions in FARM



Note: CES refers to constant-elasticity-of-substitution in Figure 1; CES refers to Clean Electricity Standard in the remainder of this paper.

is expanded to include nine electricity generating technologies; household transportation is removed from final demand to create a new production sector; household energy consumption is also removed from final demand to create a new energy services sector. Further, fossil-fuel generating technologies can be used with or without CO_2 capture and storage.

Many parameters are used to simulate energy and economic activity through 2054: some are related to technical change and others are behavioral. On the supply side, each model activity has a production function with four elasticities of substitution. Substitution elasticities are constant over time and across world regions. On the demand side, we use the Linear Expenditure System.[5]

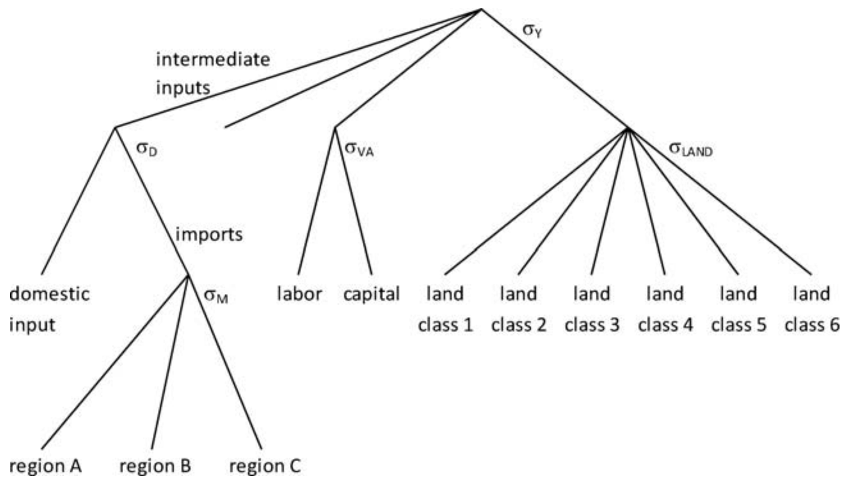
Each production sector is modeled as a nested production function as shown in Figure 1. The top nest is a constant-elasticity-of transformation (CET) function that allows joint products from a single production activity. Joint products are used selectively: one example is crude oil and natural gas production from a single production activity; another example is electricity generation and carbon sequestration from bio-electricity combined with CCS.

All other nests in Figure 1 are constant-elasticity-of-substitution: the top nest aggregates value added and intermediate inputs; the intermediate input nest embodies the Armington assumption, where inputs are distinguished by country of origin (Armington, 1969). More complex production structures can be created by combining two or more generic nesting structures.

The agricultural component of FARM allocates land across various agricultural activities, including crops, pasture, and forest. Crops are partitioned into eight crops or crop types. Five major field crops include wheat, coarse grains, rice, oil seeds and sugar. The three other crop types are

5. See Sydsaeter et al. (2010) for functional forms of constant-elasticity-of-substitution cost and production functions, and for the Linear Expenditure System.

Figure 2: Nesting structure for crops and forestry



fruits and vegetables, plant fibers, and other crops. Other agricultural activities in FARM are ruminant meat production, non-ruminant meat, dairy, and forestry. Population projections are based on the United Nations medium-fertility scenario (United Nations, 2011). With a growing world population, this requires steady improvement in crop yields. Some yield improvement is exogenous to the model, and some is price induced.

GTAP provides land use data partitioned into 18 agro-ecological zones (AEZs) within each world region (Monfreda, Ramankuty and Hertel, 2009). We aggregated GTAP AEZs into six land classes based on length of growing period, with approximately 60 days separating land classes. The six land classes divide the world into areas of progressively increasing humidity: arid, dry semi-arid, moist semi-arid, sub-humid, humid, and humid with year-round growing season (Hertel, Rose and Tol, 2009, p. 42). The land nest in Figure 2 is introduced by combining two generic production functions.

4. CO_2 EMISSIONS AND CO_2 PRICES

This section provides time paths of CO_2 emissions and CO_2 prices for selected EMF-24 reference and mitigation scenarios. Figure 3 shows the range of U.S. CO_2 emissions across all eight reference scenarios. First, note that scenarios US13 and US17 are the same: the availability of CCS does not change emissions in a reference scenario. Scenarios US01 and US19 are identical for the same reason. As expected, the reference scenario with the most optimistic technology assumptions has the lowest emissions (US13); the reference scenario with the most pessimistic technology assumptions (US23) has the highest emissions. The emissions gap between scenarios US15 and US13 is due entirely to the difference in efficiency assumptions for end-use energy technologies. The difference in emissions between scenarios US23 and US21 is due entirely to phasing out nuclear power. Therefore, the range of emissions spanned by reference scenarios is explained mostly by end-use technology assumptions and the presence or absence of nuclear power.

Figure 4 displays CO_2 emissions from selected policy scenarios. Shaded gray lines represent emissions for the 50 percent and 80 percent cap-and-trade scenarios. US09 and US10 are transportation policy scenarios; they each have about the same quantity of emissions reductions but

Figure 3: CO_2 emissions across U.S. reference scenarios

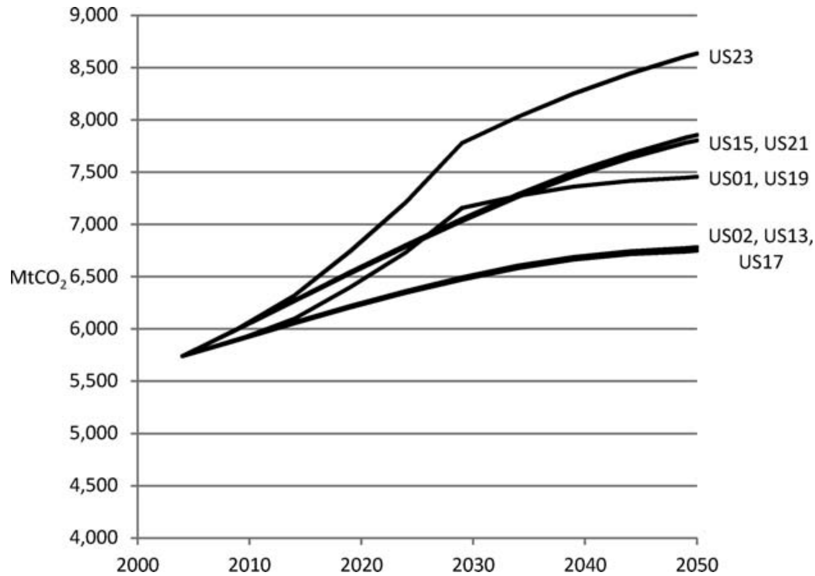
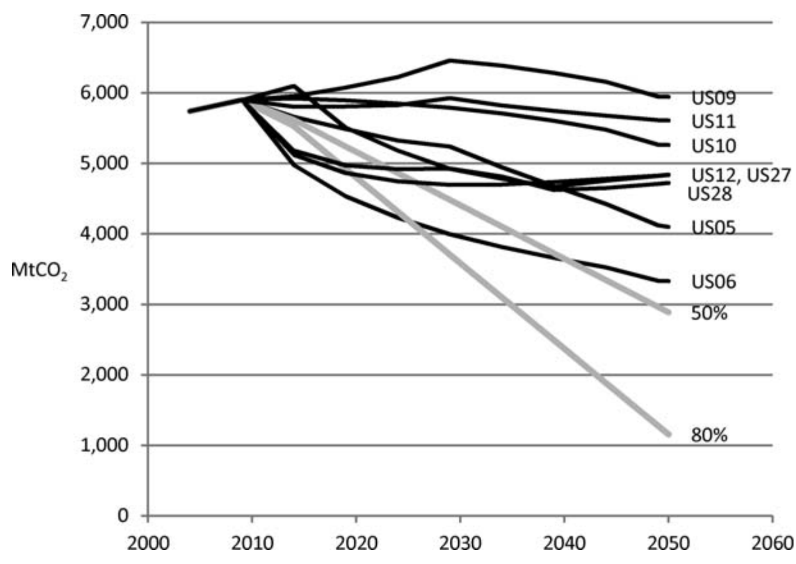


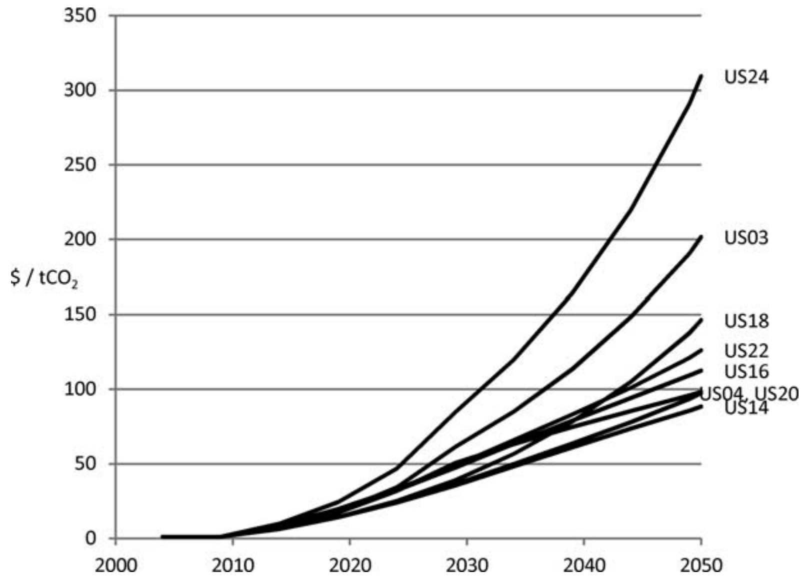
Figure 4: CO_2 emissions across U.S. policy scenarios



start from different reference scenarios. US11 and US12 combine RPS with a coal CCS policy; US27 and US28 combine CES with a coal policy. Scenarios US05 and US06 combine RPS, coal with CCS, and a transportation policy. These two mitigation scenarios provide emissions reductions comparable to a 50 percent cap-and-trade scenario.

Figure 5 provides time series of CO_2 prices for the eight 50 percent cap-and-trade scenarios that span technology assumptions. As expected, CO_2 prices are lowest in the "all good" technology scenario (US14); CO_2 prices are highest in the "all bad" technology scenario (US24). Scenario

Figure 5: CO_2 prices across 50% cap-and-trade technology scenarios (2004 US$)



US18 is particularly significant as it represents a world with optimistic technology assumptions, but without CCS. If we start with scenario US18 and phase out nuclear power, we obtain scenario US03 with the second highest CO_2 prices.

5. WELFARE AND THE EFFICIENT FRONTIER

The objective of this section is to quantify the tradeoff between emissions reductions and the cost of achieving those reductions. Various cost measures are available, such as change in consumption, change in GDP, and equivalent variation (EV). In a general equilibrium model such as FARM, equivalent variation is the preferred measure of change in welfare from a reference scenario to a corresponding mitigation scenario.[6]

EMF-24 scenarios were designed to allow calculation of this tradeoff for two reference scenarios, US01 and US02, and a number of policy scenarios. Eighteen economy-wide cap-and-trade mitigation scenarios provide varying combinations of emissions reductions and the corresponding welfare cost of achieving these reductions.[7] Hollow diamonds in Figures 6(a) and 6(b) plot these combinations relative to US01 and US02 reference scenarios respectively. Odd-numbered mitigation scenarios are matched with reference scenario US01; even-numbered mitigation scenarios are matched with reference scenario US02. Axes in Figures 6(a) and 6(b) are arranged so that the curve traced by hollow diamonds has the shape of a production possibility frontier.[8] Hollow

6. FARM uses the Linear Expenditure System for consumer demand, which is based on a shifted Cobb-Douglas utility function, allowing calculation of equivalent variation.

7. Cap-and-trade scenarios are actually simulated by varying a carbon price until the CO_2 emissions target is met. All revenue is returned as a lump sum to the representative U.S. consumer.

8. The decision to include enough cap-and-trade scenarios to trace out an efficient frontier was made during the EMF-24 meeting December 1–2, 2011 in College Park, Maryland. At that meeting, Sebastian Rausch of MIT presented scenarios from the U.S. Regional Energy Policy (USREP) model with an efficient frontier. In Figures 6(a) and 6(b), we adopt a similar format.

Figure 6(a): Tradeoff between emissions reductions and welfare

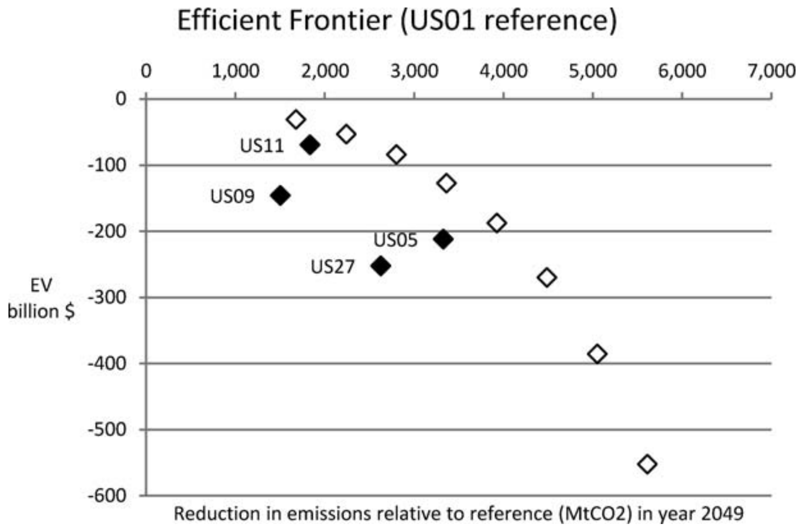
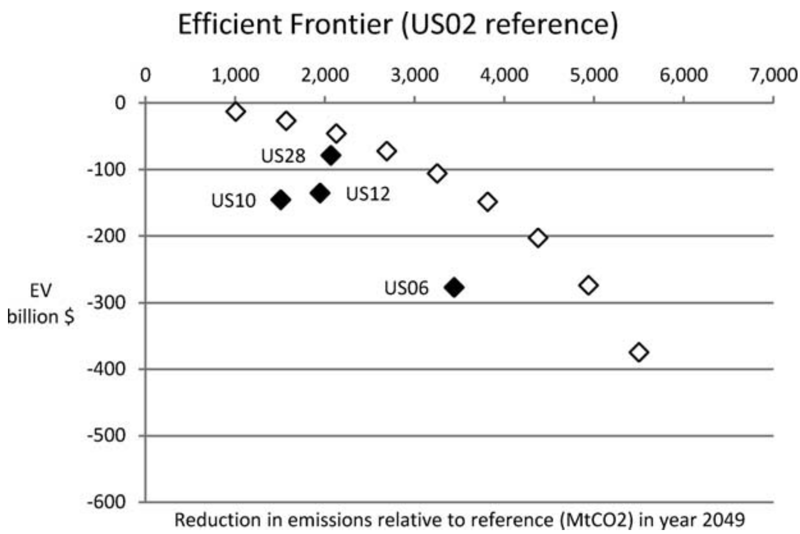


Figure 6(b): Tradeoff between emissions reductions and welfare

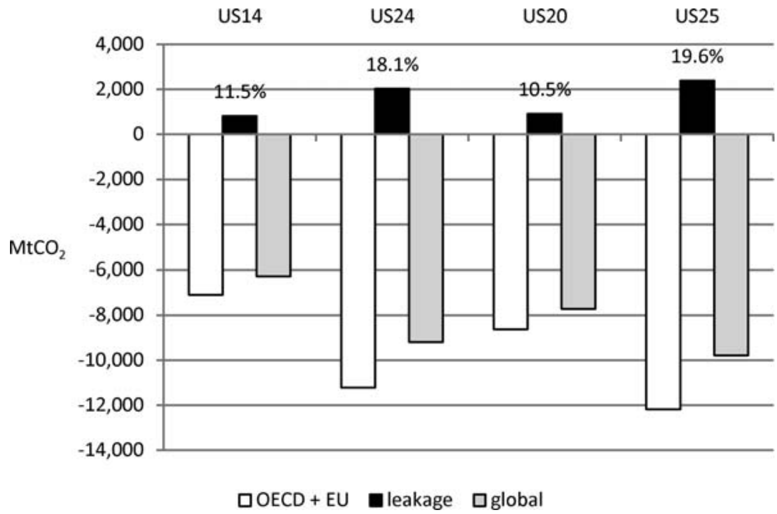


diamonds in Figures 6(a) and 6(b) trace out combinations of mitigation and economic cost for emissions reductions relative to 2005 of zero, 10, 20, 30, 40, 50, 60, and 70 percent, from left to right.[9] The reduction in emissions is the difference between reference emissions and scenario emissions in 2049, the FARM time step nearest year 2050.

Any point inside the frontier represents an inefficient use of resources, as the same CO_2 emissions reduction could have been achieved at a lower welfare cost. Solid diamonds in Figures

9. Figure 6(b) has an extra hollow diamond for an 80 percent reduction in emissions.

Figure 7: Change in emissions relative to reference scenario in 2049



6(a) and 6(b) represent eight scenarios that are combinations of mitigation strategies. Scenarios US05 and US06 target the electricity and transport sectors, with a renewable portfolio standard for electricity generation, a requirement that all new coal-fired power plants use CCS, and an efficiency target for transportation. These scenarios are expected to be less efficient than cap-and-trade, mainly because buildings and industry are excluded from the mitigation policy.

Scenarios US09 and US10 require increased energy efficiency in transportation. These scenarios were constructed with a cap-and-trade system limited to transportation emissions. The rest of the economy is excluded from this policy, so we expect this transportation-specific policy to be inside the efficient frontier. Scenarios US11 and US12 are limited to the electricity generating sector, and are also inside the efficient frontier.

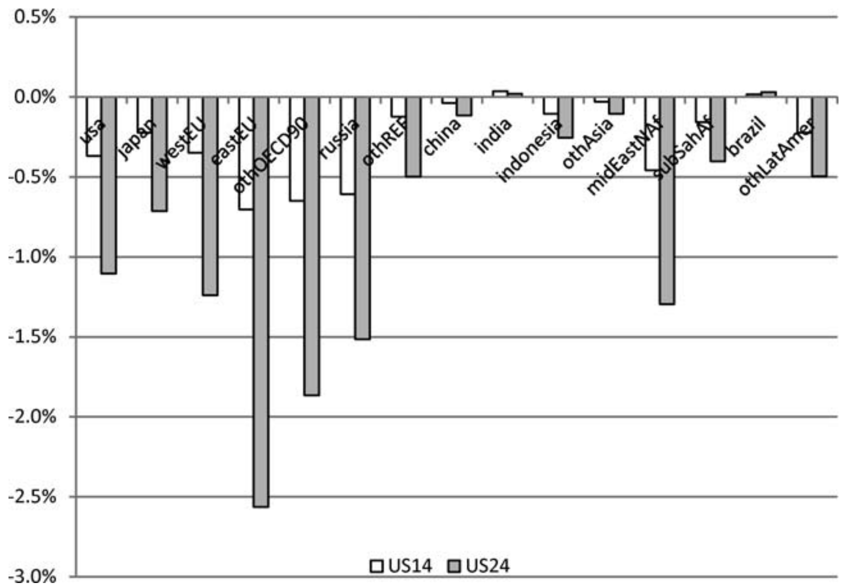
6. INTERNATIONAL IMPACTS

Our analysis of alternative U.S. CO_2 mitigation scenarios is embedded in a global computable general equilibrium model with the U.S. as one of 15 world regions. All of the pure cap-and-trade scenarios apply to the U.S., the European Union, and other countries that were members of OECD in 1990.[10] No climate policy is assumed for other world regions. While CO_2 emissions decline in each region with cap-and-trade, emissions increase in other regions, resulting in emissions leakage.

Examples of emissions leakage are displayed in Figure 7 for four cap-and-trade scenarios. The quantity of emissions leakage, shown in black bars, is the difference of emissions reductions in covered regions (OECD + EU) and global emissions reductions. An emissions leakage rate is calculated for each scenario as the ratio of emissions leakage to the reduction in OECD + EU

10. This includes five FARM regions: U.S.A., western European Union, eastern European Union, Japan, and other OECD 1990. The four regions other than U.S.A. have a common emissions market, simulated with a unified carbon price that is adjusted until total CO_2 emissions across the four regions in 2050 are 50 percent less than in 2005. This approach avoids allocating emissions rights across the four regions, and the associated wealth transfers.

Figure 8: Change in equivalent variation (as fraction of GDP) in 2039



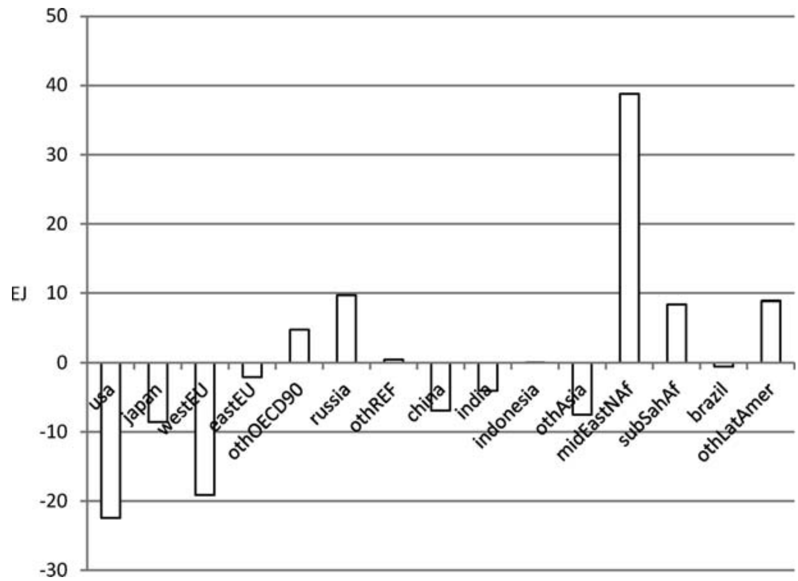
emissions. Emissions leakage rates range from 10.5 percent (scenario US20) to 19.6 percent (scenario US25).

Leakage rates in Figure 7 are in the range found in a multi-model study summarized in Böhringer et al. (2012). At least two economic mechanisms contribute to carbon leakage. First, the world price of crude oil decreases in response to a global reduction in consumption of fossil fuels. Consumption of crude oil in world regions without a carbon policy can increase with reduced prices (energy leakage channel). Second, imports and exports of energy-intensive goods also adjust to the contrast in policies between regions (production leakage). Existing results on leakage from a carbon policy in industrialized countries are mainly derived from CGE models (e.g. Kuik and Gerlagh, 2003; Kuik and Hoftes, 2010). However, the representation of production and trade in CGE models, especially constant-returns-to-scale technologies and the Armington assumption, may limit the scope for leakage (Babiker, 2005).

In Section 5 we described the tradeoff in the U.S. between reduced emissions and the cost of those reductions measured as equivalent variation. Each of the mitigation scenarios has an associated cost for regions with cap-and-trade, but there are also welfare impacts on other world regions, as shown in Figure 8. Some regions have small changes in welfare that could be either positive or negative. Scenarios US14 and US24 were selected for Figure 8 because they span a range of CO_2 prices, as seen in Figure 5. Both scenarios use cap-and-trade to reduce CO_2 emissions by 50 percent relative to year 2005, but they have opposite assumptions about the availability of technologies for reducing greenhouse gas emissions. Scenario US14 uses optimistic assumptions about technologies (end-use technology, CCS, nuclear, wind and solar, bioenergy), while US24 uses pessimistic assumptions. The welfare loss for the U.S. with pessimistic assumptions about technologies is 1.1 percent of GDP in year 2039.

A common characteristic among regions with a significant welfare loss but no climate policy (Russian Federation, Middle East and North Africa, sub-Saharan Africa, and other Latin America) is they are net exporters of crude oil. This is illustrated with oil export data from year 2004 in Figure 9.

Figure 9: Net exports of crude oil in 2004 (exajoules)



Source: Energy Balances, International Energy Agency (2011a, 2011b)

7. LAND USE

The main topic of this section is land use change in response to a U.S. CO_2 mitigation policy, in the U.S. and in countries outside the U.S. Without a CO_2 mitigation policy, land use responds to a number of drivers: income growth, population growth, and changes in agricultural technology. A CO_2 mitigation policy can also influence land use through bioenergy. In this paper, we focus on bio-electricity generated from non-food crops or short-rotation trees. The U.S. already generates about 40 terawatt-hours (TWh) of electricity with solid biomass each year (Figure 10). Although this is small compared to total electricity generated in the U.S., it could grow rapidly with a CO_2 mitigation policy.

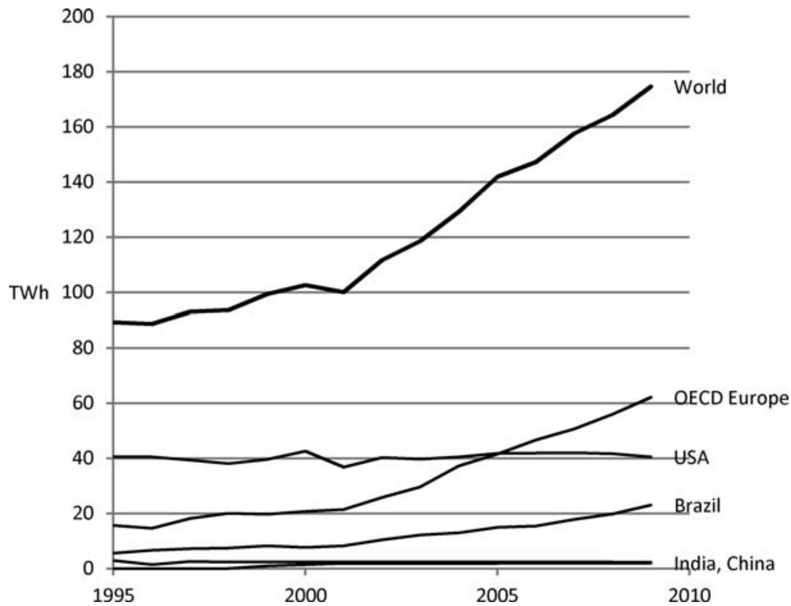
A rough rule-of-thumb is that 20 thousand hectares (kha) of cropland are required per 100 gigawatt-hours (GWh) of electricity generated.[11] Using this rule, 40 TWh (equals 40,000 GWh) for the U.S. translates to 8 million hectares of land.

Scenario US14 is a mitigation scenario that reduces U.S. carbon dioxide emissions by 50 percent from 2005 levels by year 2050. The CO_2 price in this mitigation scenario changes the relative prices of electricity across generating technologies, increasing the share of bio-electricity in the U.S. Figure 11 shows the land requirements for bio-electricity relative to land for other crops in the U.S., starting with 8 million hectares in year 2004.

Figure 12 provides another view of land for biomass relative to all major uses of land. By 2049, land for biomass as an energy crop is significant relative to other U.S. land uses, reducing the amount of land available for crops, pasture, and forestry. Land allocated to major land uses in

11. A base-year land requirement of approximately 200 kha per TWh was calculated using a net energy yield of 60 GJ per hectare for switchgrass (Schmer et al., 2008) and conversion efficiency to electricity of 30 percent.

Figure 10: Electricity generation from primary solid biomass (terawatt-hours)



Source: Energy Balances, International Energy Agency (2011a, 2011b)

Figure 11: U.S. land use for crops and biomass in mitigation scenario US14 (million hectares)

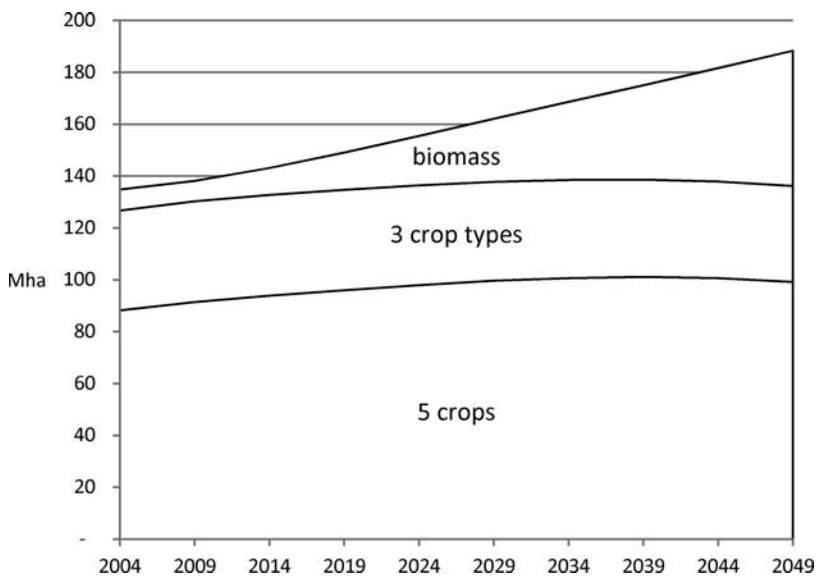


Figure 12 is fixed in total, so any increase in land for biomass is exactly offset by land for other uses.

Figure 13 displays the quantity of electricity generated from bio-electricity across eight 50 percent cap-and-trade mitigation scenarios. As expected, scenarios with low bioenergy potential

Figure 12: U.S. land use for mitigation scenario US14 (million hectares)

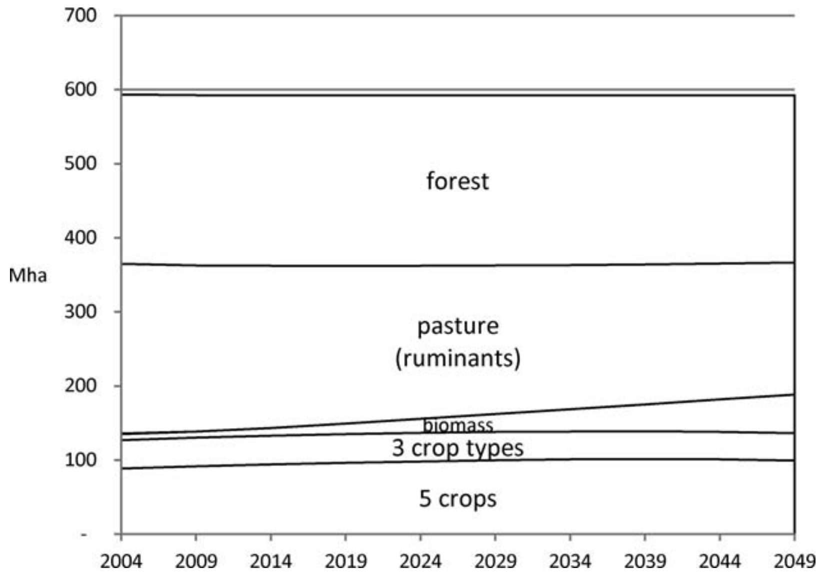
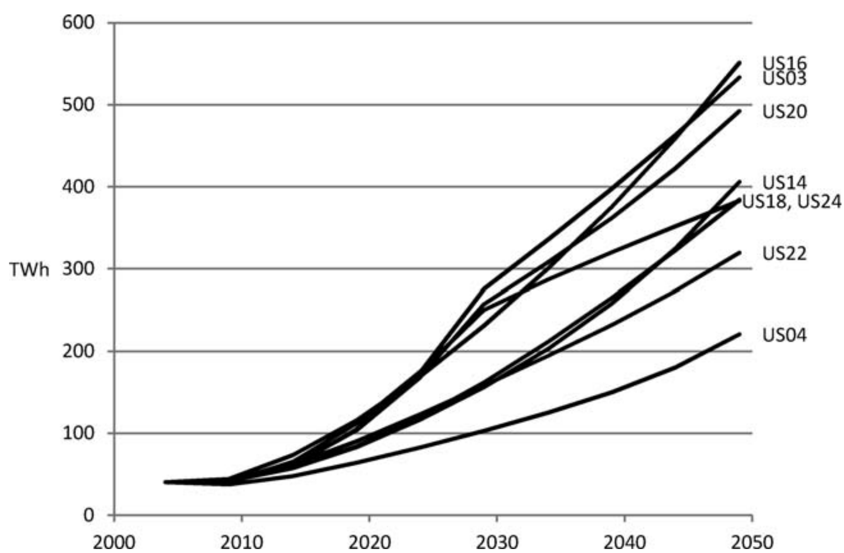


Figure 13: U.S. bio-electricity generation across technology scenarios (TWh)



(US04, US22) generate the least amount of bio-electricity. Three scenarios with the greatest quantity of bio-electricity are clustered in a group at the top of Figure 13 (US20, US03, and US16). In each of these scenarios, the potential for bioenergy is high and bio-electricity is compensating for the lack of nuclear power or end-use efficiency. Bio-electricity is not as effective at compensating for a lack of CCS (US18) because bio-electricity uses CCS whenever it is available for fossil generating technologies.

Figure 14: Land use change (US14 – US13) in year 2050 (million hectares)

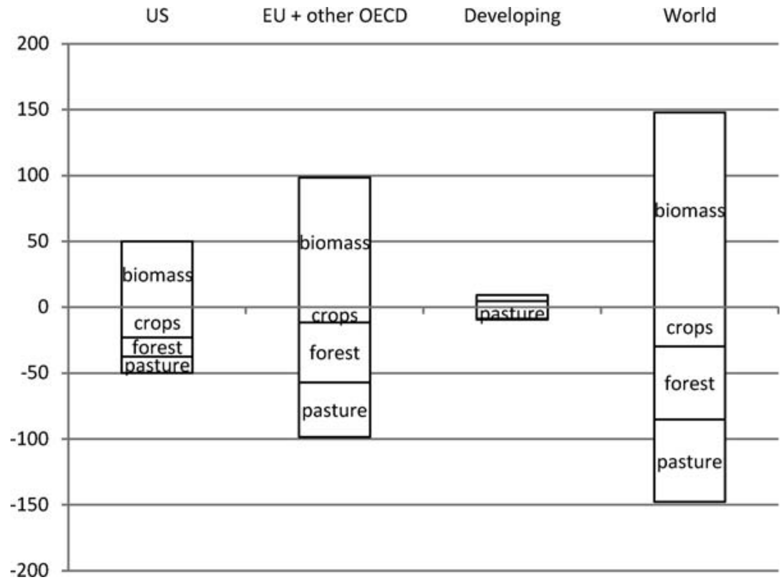


Figure 14 displays the change in land use for mitigation scenario US14 relative to reference scenario US13 as the difference in area of each land use type, in year 2050. As expected, land for biomass increases in regions with a cap-and-trade mitigation policy. In the U.S., the expansion of land used for biomass is exactly offset by reductions in cropland, forest, and pasture. The same is true for OECD countries other than the U.S., but with a small decrease in cropland. Land use changes very little in developing countries, with a very small increase in cropland and forest. Relative productivity growth rates across crops, livestock and forestry for developing and developed countries will influence the pattern of land use change (Jones and Sands, 2013).

8. CONCLUSIONS

We set out to address questions related to alternative technology and policy scenarios for CO_2 mitigation in the U.S. from the present through 2050. How do alternative technology and policy scenarios for CO_2 mitigation in the U.S. affect economic welfare and land use? Are there significant spillover effects through international trade? Our analysis is framed in a global computable-general-equilibrium model with a balanced representation of energy and agricultural systems.

Our simulations demonstrate that U.S. and other OECD mitigation activities may have significant impacts through international trade. First, emissions outside the OECD increase in response to OECD CO_2 mitigation policies. This leakage rate is in the range of 11 to 20 percent, depending primarily on the stringency of OECD mitigation targets. Second, some regions outside the OECD have significant reductions in economic welfare, as measured by equivalent variation, in response to CO_2 mitigation in OECD countries. Although the loss in welfare outside the OECD is smaller than the welfare loss in the OECD, it is concentrated in regions that are net exporters of crude oil. Third, the mitigation scenarios specified in EMF-24 are stringent enough to significantly increase the quantity of solid biomass used to generate electricity in the U.S.

Many of the scenarios in EMF-24 are used solely to trace the tradeoff between economic cost and reductions of CO_2 emissions with economy-wide cap-and-trade. Other mitigation scenarios with less than economy-wide coverage were all found to be less efficient: the same quantity of emissions reduction could be achieved at a lower cost with economy-wide cap-and-trade.

In scenarios with expansion of bio-electricity, land used for biomass production displaces other land uses, including pasture and forests. A full analysis of mitigation policy would require consideration of CO_2 emissions from land use change, as above- and below-ground carbon stocks reach a new equilibrium.

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Markets versus Regulation: The Efficiency and Distributional Impacts of U.S. Climate Policy Proposals

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ABSTRACT

Regulatory measures have proven the favored approach to climate change mitigation in the U.S., while market-based policies have gained little traction. Using a model that resolves the U.S. economy by region, income category, and sector-specific technology deployment opportunities, this paper studies the magnitude and distribution of economic impacts under regulatory versus market-based approaches. We quantify heterogeneity in the national response to regulatory policies, including a fuel economy standard and a clean or renewable electricity standard, and compare these to a cap-and-trade system targeting carbon dioxide or all greenhouse gases. We find that the regulatory policies substantially exceed the cost of a cap-and-trade system at the national level. We further show that the regulatory policies yield large cost disparities across regions and income groups, which are exaggerated by the difficulty of implementing revenue recycling provisions under regulatory policy designs.

Keywords: Energy modeling, Climate policy, Regulatory policies, Electricity, Transportation, General Equilibrium Modeling

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1. INTRODUCTION

In the absence of comprehensive legislation to curb greenhouse gas (GHG) emissions in the United States, policymakers have been pursuing climate change mitigation through sector or technology-specific regulatory measures. Comprehensive climate policies would cover most or all sources of GHG emissions and incentivize reductions at least cost through a market mechanism—such as a carbon tax, cap-and trade system, or hybrid instrument—by achieving an equalization of marginal abatement costs across participants (Metcalf, 2009). Regulatory measures, by contrast, require that GHG emissions reductions be achieved through compliance with sector-specific technology or efficiency targets. Examples of such regulatory measures include new source performance standards for power plant pollutant emissions, vehicle fuel economy standards, renewable or low carbon fuel standards, and renewable or clean electricity standards.

This paper examines the efficiency and distributional implications of federal regulation in the U.S. electric power and transportation sectors by employing a numerical simulation model with

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a unique treatment of regional, technology, and household income heterogeneity. The goal is to closely approximate current proposals implemented or under consideration in the U.S.

We investigate the impact on economy-wide costs and emissions reductions of introducing a clean energy standard (CES) or renewable portfolio standard (RPS), which would mandate the introduction of renewable generation (as well as other cleaner fuel sources in a CES), and a vehicle fuel economy standard modeled after the U.S. Corporate Average Fuel Economy (CAFE) Program, which mandates increases in on-road fuel economy of new vehicles sold in each vehicle model year. We explore how the costs are distributed across households in different regions and income categories. We compare the cost effectiveness and the distribution of impacts of policies alone and in combination, and investigate the welfare impact of such policies relative to an efficient instrument (in this case, a cap-and-trade system that creates a market for emissions permits).[1]

This paper proceeds as follows. Section 2 describes the numerical model used for quantitative policy assessments. Section 3 describes and interprets the model results. Section 4 performs a structural sensitivity analysis by investigating the impact of electricity policies in a coupled modeling framework that introduces a more detailed representation of technology. Section 5 concludes.

2. THE U.S. REGIONAL ENERGY POLICY (USREP) MODEL

2.1 Data

This study makes use of a comprehensive energy-economic dataset that features a consistent representation of energy markets in physical units as well as detailed economic accounts of regional production, bilateral trade, and energy resources for the year 2006. The data set merges detailed state-level data for the U.S. with national economic and energy data. Social accounting matrices (SAM) in our hybrid dataset are based on data from the IMPLAN (IMpact analysis for PLANning) data (IMPLAN, 2008) and U.S. state-level accounts of energy balances and prices from the Energy Information Administration (EIA, 2009). Table 1 provides an overview of the data sources used.

The IMPLAN data provide consistent regional accounts of production, consumption, and bilateral trade for the 50 U.S. states (and the District of Columbia). The dataset includes input-output tables for each state that identify 509 commodities and existing taxes. Bilateral state-to-state trade data in the IMPLAN database are derived using a gravity approach (Lindall et al., 2006).[2] The base year for the IMPLAN accounts in the version we use here is 2006. To improve the

1. It is important to note that this paper does not aim at identifying any optimal mix of policy instruments nor does it claim that an economy-wide cap-and-trade regulation is always the most cost-effective policy instrument. Cost-effectiveness depends importantly on how policies interact with distortions in the economy created by the broader fiscal system (see, for example, Harberger, 1964; Bovenberg & Goulder, 1996; Goulder et al., 1999). The costs of market-based policies that do not offset the tax-interaction effect with the revenue-recycling benefit can be dramatically higher, particularly for the scale of CO_2 reductions considered here (Parry & Williams III, 2011). Regulatory approaches targeted to individual sectors would thus be less attractive relative to a comprehensive cap-and-trade policy if the latter would exploit revenue recycling options. As we assume throughout the paper that the revenue from a federal cap-and-trade regulation is recycled lump-sum, the estimates concerning the relative cost-effectiveness of regulatory policies provided in this paper should be best viewed as providing a lower bound.

2. The IMPLAN Trade Flows Model draws on three data sources: the Oak Ridge National Labs county-to-county distances by mode of transportation database, the Commodity Flows Survey (CFS) ton-miles data by commodity, and IMPLAN commodity supply and demand estimates by county.

Table 1: Data sources

Data and parameters	Source
Social accounting matrices	IMPLAN (2008)
bi-lateral trade	Gravity-based analysis (Lindall et al., 2006)
pooled energy trade	State Energy Data System, (EIA, 2009)
Physical energy flows and energy prices	State Energy Data System, (EIA, 2009)
Fossil fuel reserves and biomass supply	U.S. Geological Survey (USGS, 2009)
	U.S. Department of Energy (DOE, 2009), Dyni (2006) and Oakridge National Laboratories (2009)
High-resolution wind data	Wind Integration Datasets, National Renewable Energy Laboratory (NREL, 2010)
Non-CO_2 GHG inventories and endogenous costing	U.S. Environmental Protection Agency (EPA, 2009)
	Hyman et al. (2002)
Marginal personal income tax rates	NBER's TAXSIM model (Feenberg & Coutts, 1993)
Trade elasticities	Global Trade Analysis Project (2008) and own calibration
Energy demand and supply elasticities	Paltsev et al. (2005)
Passenger vehicle transportation	U.S. Department of Transportation (2009)

Figure 1: Regions in the USREP model

characterization of energy markets in the IMPLAN data, we use constrained least-squares optimization techniques to merge IMPLAN data with data on physical energy quantities and energy prices from the Energy Information Administration's State Energy Data System for 2006 (EIA, 2009).[3]

For this study, we aggregate the dataset to 12 U.S. regions, 10 commodity groups, and 9 households grouped by annual income classes (see Table 2). States identified in the model include California, Texas, Florida, and New York, along with several other multi-state regional composites. Mapping of states to aggregated regions is shown in Figure 1. This structure separately identifies larger states, allows representation of separate electricity interconnects, and captures some of the diversity among states in use and production of energy. Our commodity aggregation identifies five

3. Aggregation and reconciliation of IMPLAN state-level economic accounts to generate a micro-consistent benchmark dataset which can be used for model calibration is accomplished using ancillary tools documented in Rausch & Rutherford (2009).

Table 2: USREP model details

Sectors	Regions	Primary production factors
Non-Energy	Pacific (PACIF)	Capital
Agriculture (AGR)	California (CA)	Labor
Services (SRV)	Alaska (AK)	Coal resources
Energy-intensive products (EIS)	Mountain (MOUNT)	Natural gas resources
Other industries products (OTH)	North Central (NCENT)	Crude oil resources
Commercial Transportation (TRN)	Texas (TX)	Hydro resources
Household vehicle transportation (HVT)	South Central (SCENT)	Nuclear resources
Final demand sectors	North East (NEAST)	Wind resources
Household transportation	South East (SEAST)	Land
Other household demand	Florida (FL)	
Government demand	New York (NY)	
Investment demand	New England (NENGL)	
Energy supply and conversion	Household income classes ($1,000 of annual income)	
Fuels		
Coal (COL)	<10	
Natural gas (GAS)	10–15	
Crude oil (CRU)	15–25	
Refined oil (OIL)	25–30	
Electricity (ELE)	30–50	
Conventional fossil	50–75	
Existing nuclear	75–100	
Hydro	100–150	
Advanced energy supply technologies (see Table 3)	>150	

energy sectors and five non-energy composites. Energy commodities include coal (COL), natural gas (GAS), crude oil (CRU), refined oil (OIL), and electricity (ELE), which distinguishes energy goods and specify substitutability between fuels in energy demand. Elsewhere, we distinguish energy-intensive products (EIS), other manufacturing (OTH), agriculture (AGR), commercial transportation (TRN), household vehicle transportation (HVT), and services (SRV). Primary factors in the dataset include labor, capital, land, as well as fossil fuels and natural resources.

We forecast both CO_2 and non-CO_2 greenhouse gases. Non-CO_2 greenhouse gases are based on U.S. EPA inventory data (EPA, 2009), and are included following the approach in Paltsev et al. (2005) with endogenous costing of abatement measures (Hyman et al., 2002). Energy supply is regionalized by incorporating data for regional crude oil and natural gas reserves (DOE, 2009), coal reserves estimated by the U.S. Geological Survey (USGS, 2009), and shale oil (Dyni, 2006). Our approach to characterize wind resource and incorporate electricity generation from wind in the model is described in detail in Section 4.1. We derive regional supply curves for biomass from data from Oakridge National Laboratories (2009) that describes quantity and price pairs for biomass supply for each state.

Our data set permits calculation of existing taxes rates comprised of sector and region-specific ad valorem output taxes, payroll taxes and capital income taxes. The IMPLAN data has been augmented by incorporating regional tax data from the NBER TAXSIM model (Feenberg & Coutts, 1993) to represent marginal personal income tax rates by region and income class.

2.2 Model Overview

Our modeling framework draws on a multi-commodity, multi-region, multi-household numerical general equilibrium model of the U.S. economy. The key features of the model are briefly

Table 3: Advanced energy supply technologies

Technology	Description
Coal gasification	Converts coal into a perfect substitute for natural gas.
Biomass liquids	Converts biomass into a perfect substitute for refined oil.
Biomass electricity	Converts biomass into a perfect substitute for electricity.
Wind without backup	Converts intermittent wind resources into an imperfect substitute for electricity.
Wind with gas backup	Creates a perfect substitute for electricity by jointly building wind turbines and natural gas generation.
Wind with biomass backup	Creates a perfect substitute for electricity by jointly building wind and biomass generation.
Advanced gas	Based on natural gas combined cycle (NGCC) technology that converts natural gas into electricity.
Advanced gas with CCS	Natural gas combined cycle technology that captures 90% or more of the CO_2 produced in generating electricity.
Advanced coal with CCS	Integrated coal gasification combined cycle (IGCC) that captures 90% or more of the CO_2 produced in generating electricity.
Advanced nuclear	Next generation of nuclear power plants incorporating estimated costs of building new nuclear power plants in the future.

outlined below and described in detail in Rausch et al. (2010a, 2010b).[4] The model assumes a recursive-dynamic approach implying that economic agents have myopic expectations and base their decisions on current period information.

In each industry gross output is produced using inputs of labor, capital, and natural resources including coal, natural gas, crude oil, and land, and produced intermediate inputs. We employ constant-elasticity-of-substitution (CES) functions to characterize how production technologies respond to changes in energy and other input prices; the IMPLAN data describe the initial production systems. All industries are characterized by constant returns to scale (except for fossil fuels and agriculture, which are produced subject to decreasing returns to scale) and are traded in perfectly competitive markets.

Advanced energy supply options are specified as "backstop" technologies that enter endogenously if and when they become economically competitive with existing technologies. Competitiveness of advanced technologies depends on their initial cost disadvantage compared to conventional technologies, in addition to the endogenously determined input prices. The advanced technology options are summarized in Table 3.

Three technologies produce perfect substitutes for conventional fossil fuels (natural gas from coal, a crude oil product from shale oil, and refined oil from biomass). The remaining nine are electricity generation technologies (biomass, wind without backup, wind with gas backup, wind with biomass backup, natural gas combined cycle with and without carbon capture and sequestration, integrated coal gasification combined cycle with and without carbon capture and sequestration, and advanced nuclear). We adopt a top-down approach of representing technologies following Paltsev et al. (2005, pp. 31–42) where each technology can be described through a nested CES function. The logic behind our approach to represent electricity generated from intermittent wind resources is explained in detail in Section 4.1.

Consumption, labor supply, and savings result from the decisions of representative households in each region maximizing utility subject to a budget constraint that requires that full con-

4. These papers also provide detail on the elasticities of substitution used to parameterize the model which we do not provide below.

sumption equals income in a given period. Lacking specific data on capital ownership, households are assumed to own a pool of U.S. capital—that is they do not disproportionately own capital assets within the region in which they reside.[5] Given input prices gross of taxes, firms maximize profits subject to technology constraints.

Firms operate in perfectly competitive markets and maximize their profit by selling their products at a price equal to marginal costs. In each region, a single government entity approximates government activities at all levels— federal, state, and local.

We adopt a putty-clay approach where a fraction of previously installed capital becomes non-malleable and frozen into the prevailing techniques of production. Vintaged production in a given industry that uses non-malleable capital is subject to a fixed-coefficient transformation process in which the quantity shares of capital, labor, intermediate inputs and energy by fuel type are set to be identical to those that prevailed in the period when the capital was installed. Each of the sector-specific vintages is tracked through time as a separate capital stock. This formulation means that the model exhibits a short-run and long-run response to changes in relative prices. The substitution response in a single period to a change in prices in that period is a combination of the long-run substitution possibilities, weighted by output produced by malleable capital, and no substitution, weighted by output produced with vintaged capital.

With the exception of crude oil, which is modeled as a homogeneous good, intermediate and final consumption goods are differentiated following the Armington (1969) assumption. For each demand class, the total supply of a particular good is a CES composite of a domestically produced variety (i.e., locally produced and imported from domestic markets) and an imported (from foreign markets) one. As described in Rausch et al. (2010), USREP models the U.S. as a large open economy with price-responsive imports and exports to and from international markets.

All goods are tradable. Depending on the type of commodity, we distinguish three different representations of intra-national trade. First, bilateral flows for all non-energy goods are represented as Armington goods, which like goods from other regions are imperfectly substitutable for domestically produced goods. Second, domestically traded energy goods, except for electricity, are assumed to be homogeneous products, i.e. there is a national pool that demands domestic exports and supplies domestic imports. This assumption reflects the high degree of integration of intra-U.S. markets for natural gas, crude and refined oil, and coal. Third, we differentiate six regional electricity pools that are designed to provide an approximation of the existing structure of independent system operators (ISO) and the three major interconnections in the U.S. More specifically, we distinguish the Western, Texas ERCOT and the Eastern interconnections and in addition identify AK, NENGL, and NY as separate regional pools.[6] Within each regional pool, we assume that traded electricity is a homogenous good, and that no electricity is traded among regional pools.

Our framework incorporates a detailed representation of passenger vehicle transport that permits projections of vehicle-miles traveled (VMT), fleet stock turnover, and fuel price-induced investment in fuel efficiency. This permits studies of policies that target improvements in vehicle

5. The ownership of natural resources and wind is, however, assumed to be regional. Lacking empirical data on ownership patterns from these resources, the alternative and extreme case would be to assume that income from natural resources is also distributed in proportion to capital. On the one hand, the assumption of pooled ownership of capital tends to average out distributional impacts across the nation, while on the other hand the assumption of regional ownership of natural resources may overestimate the size of regional impacts.

6. The regional electricity pools are thus defined as follows: NENGL, NY, TX, AK each represent a separate pool. The Western interconnection comprises CA, MOUNT, and PACIF. The Eastern interconnection comprises NEAST, SEAST, and FL.

fuel efficiency, differentiate between newly purchased and pre-existing vehicle stocks in each period, and result in changes in overall vehicle-miles traveled as well as the fuel use and GHG emissions of new and pre-existing vehicles. These features are similar to those introduced into the MIT EPPA model (Paltsev et al., 2005) and are described in detail in Karplus et al. (2013b).

Numerically, the equilibrium is formulated as a mixed complementarity problem (MCP) (Mathiesen, 1985; Rutherford, 1995). Our complementarity-based solution approach comprises two classes of equilibrium conditions: zero profit and market clearance conditions. The former condition determines a vector of activity levels and the latter determines a vector of prices. We formulate the problem in GAMS and use the mathematical programming system MPSGE (Rutherford, 1999) and the PATH solver (Dirkse & Ferris, 1995) to solve for non-negative prices and quantities.

3. RESULTS

3.1 Scenarios

Our core scenarios follow the policy scenarios defined in the EMF 24 U.S. study (see the overview paper of this study; Fawcett et al., 2012). In addition to a business-as-usual scenario ("BAU", called "US01F"),[7] we consider the following six policy scenarios: (1) a national cap-and-trade policy that allows for cumulative GHG emissions from 2012 through 2050 associated with a linear reduction from 2012 levels to 50% below 2005 levels in 2050 ("CAT50%", "US03F"), (2) a federal renewable portfolio standard for electricity which mandates that 20% by 2020, 30% by 2030, 40% by 2040, and 50% by 2050 of electricity has to be produced from renewable energy (including hydropower), and that all new coal power plants capture and store more than 90% of their CO_2 emissions ("Electricity (Coal + RPS)", "US11F"), (3) a federal clean energy standard for electricity under which all renewable energy sources and nuclear receive full credit while fossil electricity with carbon capture and storage (CCS) technologies are credited at 90% and natural gas at 50% with targets defined as linearly increasing from reference levels in 2012 to 50% by 2020, 60% by 2025, 70% by 2030, 80% by 2035, 90% by 2040 and thereafter ("Electricity (Coal + CES)", "US27F"), (4) a federal transport policy establishing a fuel economy standard for new light-duty vehicles that specifies a linear increase in the fuel economy of new vehicles, starting in 2012, to 3 times 2005 levels sectors ("Electricity (Coal + RPS) & Transport", "US05F"), (5) a scenario that combines both regulatory policies for the electricity and transportation sectors ("Electricity (Coal + RPS) & Transport", "US05F"), and (6) a scenario that layers a federal cap-and-trade policy on top of the two sectoral policies ("Electricity (Coal + RPS) & Transport & CAT50%", "US07F").

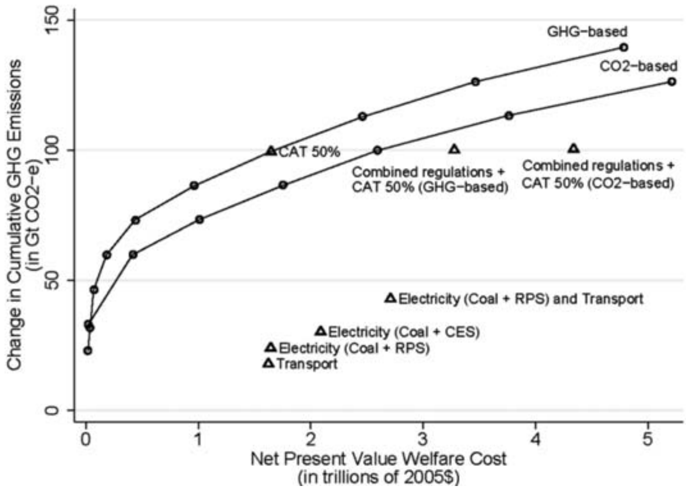
Throughout all scenarios—including the regulatory policy scenarios—real government spending is held fixed at the baseline ("BAU") level through endogenous lump-sum transfers or taxes. These are assumed to be uniform across households in different regions and income classes.

3.2 Cost effectiveness

The cost effectiveness of policy is inherently linked to abatement flexibility. Important sources of flexibility include the ability to allocate abatement across gases, sectors, technologies,

7. The first label specifies the scenario name used in this paper; the second label refers to the scenario name used in the overview piece of the EMF24 study.

Figure 2: Net present value (NPV) of welfare cost and cumulative GHG emissions reductions of regulatory and market-based climate policies



Note: NPV is calculated using an annual discount rate of 4%. "GHG-based" refers to CAT policies designed to achieve emissions reduction from multiple greenhouse gases based on their CO_2 equivalents. "CO_2-based" refers to CAT policies that only target CO_2.

and time. To the extent that target gas, sector, technology, and timetable are constrained, regulatory policies will impose equal or greater costs relative to an economy-wide market-based instrument with full flexibility (in a first-best setting). Adding regulatory policies in the presence of an economy-wide instrument also reduces abatement flexibility, as specified sectors or technologies deliver a portion of the overall reduction that would otherwise represent least cost solutions. These observations are consistent with the theoretical and empirical literature (Paltsev et al., 2009; Böhringer & Rosendahl, 2010; Fischer & Preonas, 2010; Pethig & Wittlich, 2009; Gonzalez, 2007). In contrast to both cap-and-trade instruments, all of the regulatory policies implemented, and as modeled here, are constrained to act on a target sector and fixed abatement schedule, significantly reducing abatement flexibility.[8]

Our analysis illustrates the welfare penalties associated with reductions in abatement flexibility. Figure 2 shows for each policy the percentage change in cumulative GHG (or CO_2 emissions from 2012–2050 against the net present value of welfare change over the same period, expressed in trillion 2005$. Welfare costs are measured as equivalent variation relative to the baseline (no policy) scenario. The two solid lines show "efficient" abatement frontier, i.e. the locus of points that corresponds to the impact of a market mechanism (here modeled as a system of tradable

8. In the presence of distorted factor markets, however, it is not clear a priori that a cap-and-trade policy is superior in terms of welfare compared to a regulatory policy. Cap-and-trade policies may lead to a large increase in the price of consumption relative to a regulatory policy, thus implying a lower real wage and a larger reduction in labor supply. If there are pre-existing taxes on labor, the reduction in labor supply has a first-order efficiency cost, which has been termed the tax-interaction effect (Parry et al., 1998), and can be larger under a cap-and-trade relative to a regulatory policy. Similar effects might arise if intra- and intertemporal distortions associated with capital markets are corrected. On the other hand, regulatory policies fail to exploit the revenue-recycling effect as they do not generate revenue that can be used to cut distortionary marginal tax rates. Initial exploratory analysis with the USREP model did find evidence for a strong tax-interaction effect that would make regulatory policies more cost effective.

permits). The frontiers are shown both for policies that constrain all GHGs or CO_2 only. Reducing coverage from all GHGs to CO_2 alone adds to the cost of policy, corresponding to a shift of the frontier to the right. Both of these policies retain broad sectoral coverage and inter-temporal flexibility through provisions for banking and borrowing.[9]

The two frontiers corresponding to GHG and CO_2 cap-and trade instruments in Figure 2 provide a benchmark against which the various regulatory policies can be compared. We first consider combinations of cap-and-trade policies with regulatory instruments. At the national level we find that the welfare reduction generated by the CAT50% ranks among the smallest of all the policies, while it produces the largest total cumulative reduction. Adding the vehicle fuel economy and electricity regulations to the CO_2 or GHG cap-and-trade policy increases the total discounted welfare cost by 60% or 90%, respectively.

All of the regulatory policies produce points located inside (and far from) the efficient frontier. Figure 2 shows the magnitude of the welfare penalty associated with each of the regulatory instruments in terms of how they compare to both the efficient frontiers as well as to each other. In all cases, the emissions reductions achieved are much lower, given that policies target modest reductions from specific sectors. These reductions, however, are achieved with far less cost-effective solutions— for the same cost, a fuel economy standard ("transport") or a renewable-energy based electricity standard ("Coal + RPS") would achieve only one-fourth of the reductions attained under a cap-and-trade system. Put differently, an equivalent level of emissions reduction could be achieved under a cap-and-trade system for less than 5% of the cost of either regulatory policy. The large discrepancy can be traced back to abatement flexibility—regulatory policies imposed on the electricity or transportation sectors would encourage the application of only a subset of the abatement options that a cap-and-trade policy would employ. Indeed, the cost of combining the two regulatory policies exceeds that of a cap-and-trade system (1.1% compared to 0.9%), while the emissions reductions are barely half of the level achieved under a cap-and-trade system.

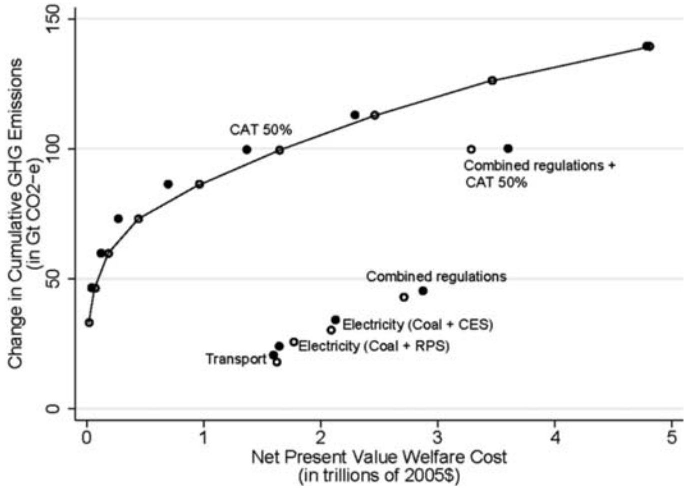
These results are not markedly affected by alternative assumptions for technology cost, as shown in Figure 3. We examine a case with low CCS/nuclear and high renewable energy costs and one with the reverse, high CCS/nuclear and low renewable energy costs. On the frontier, sensitivity of the total cost to changes in relative costs of these electricity sector abatement options initially increases with the magnitude of emissions reductions required, before decreasing again at reduction levels upwards of around 125 Gt $CO_{2\text{-eq.}}$, suggesting that at higher levels of reduction the relative costs no longer affect technology deployment decisions at the margin. The direction of the effect in the electricity scenarios depends on the role of renewable energy and carbon capture and storage (CCS) as the preferred solution under the policy constraint: high cost renewable energy increases the cost of compliance in the "Coal + RPS" scenario, but has less of an effect in the "Coal + CES" policy given that other low carbon alternatives, particularly natural gas, can be used to comply with the policy. The GHG emissions reduction trajectories under each policy over time are shown in Figure 4.

3.3 Effect on emissions by sector

We now turn to consider the distribution of impacts by sector, shown in Table 4. The cap-and-trade policy elicits broad sectoral participation (we focus here only on the GHG policy), with

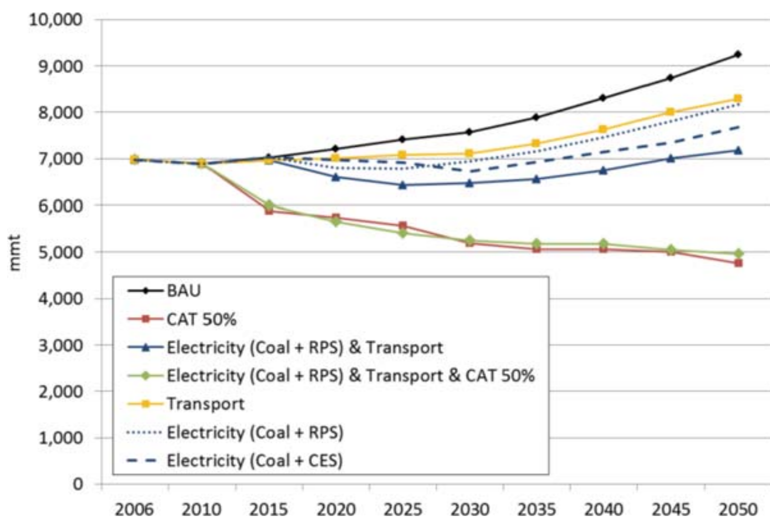
9. It should be noted that there may be cap-and-trade policies that are more cost effective due to exploiting the revenue-recycling effect.

Figure 3: Net present value (NPV) of welfare cost and cumulative GHG emissions reductions of regulatory and market-based climate policies for different technology sensitivities



Note: NPV calculated using an annual discount rate of 4%. Hollow circles refer to "Low CCS/Nuclear and High Renewable Energy" technology assumptions. Solid circles refer to "High CCS/Nuclear and Low Renewable Energy" technology assumptions.

Figure 4: US GHG emissions over time



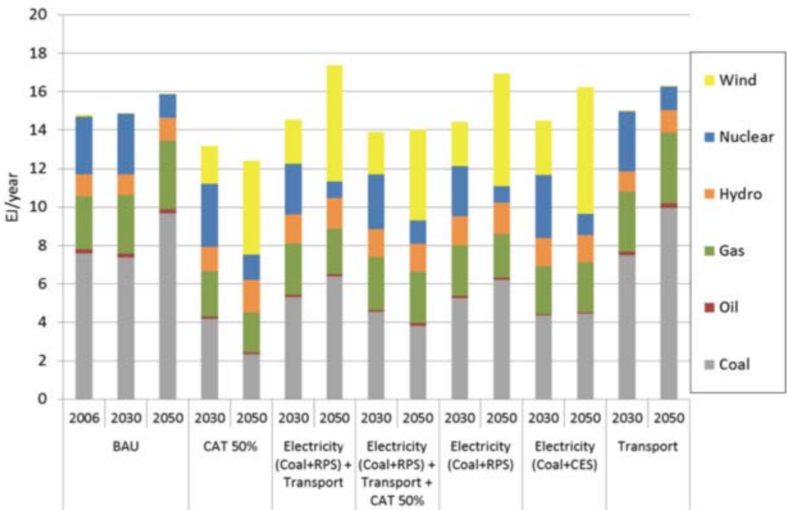
the reduction burden spread across the electricity, agriculture, energy-intensive industries, manufacturing, and commercial transport sectors. Private transport, by contrast, proves to be a relatively costly abatement option, consistent with other studies, and does not participate significantly in the least-cost response (Karplus, 2013a; Davidson & van Essen., 2009; Schafer & Jacoby, 2006). Under a policy that targets private and commercial transport, reductions in these sectors (19% and 18%, respectively) substantially exceed those resulting under a cap-and-trade system, with additional

Table 4: Percentage change in cumulative (2012–2050) U.S. GHG emissions by sector and sectoral contribution to overall abatement

All sectors	Commercial transport	Private transport	Electricity	Agriculture	Energy-intensive industries	Refined oil	Manufacturing	Services
CAT 50%								
−22	−8 (9)	−3 (2)	−33 (44)	−45 (16)	−23 (10)	−24 (5)	−44 (12)	−25 (3)
Transport								
−7	−19 (68)	−18 (37)	1 (−5)	2 (−2)	2 (−3)	−17 (10)	5 (−4)	1 (−0)
Electricity (Coal + RPS)								
−6	−0 (1)	0 (−0)	−20 (95)	−1 (2)	−0 (0)	0 (0)	−1 (1)	−3 (1)
Electricity (Coal + CES)								
−7	0.0 (−0)	0 (−1)	−25 (99)	−1 (1)	1 (−1)	−0 (0)	−1 (1)	−1 (0)
Electricity (Coal + RPS) & Transport								
−14	−20 (37)	−18 (20)	−18 (40)	1 (−0)	2 (−1)	−17 (5)	4 (−2)	−2 (0)
Electricity (Coal + RPS) & Transport & CAT 50%								
−25	−21 (21)	−19 (12)	−28 (34)	−41 (13)	−14 (5)	−27 (5)	−35 (9)	−20 (2)

Note: Figures before parentheses refer to percentage change in emissions by sector relative to “business-as-usual”. Figures in parentheses refer to sectoral emissions reductions as a percentage of total abatement relative to “business-as-usual”.

Figure 5: U.S. electricity generation mix by 2030 and 2050



modest reductions in other sectors resulting from the indirect effects on income and prices imposed by the policy. Combining electricity and transport regulatory policies results in nearly additive total reductions (14%), given that these activities are largely separate and co-benefits are limited.

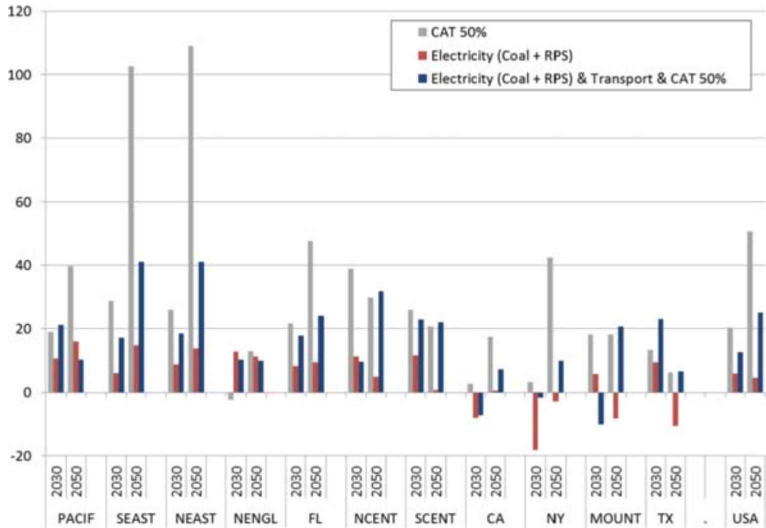
Comparing the cap-and-trade policy combined with regulatory policies to the cap-and-trade policy imposed alone, we find that the regulatory policies significantly increase the contribution of the electricity and transport sectors to overall abatement at the expense of more cost effective abatement opportunities in agriculture, energy-intensive industries, and manufacturing. For example, the contribution of the energy-intensive industries to overall abatement drops from 23% to 14% when both regulatory policies are added to a cap-and-trade system, and similar decreases are observed for agriculture, manufacturing, and services. This response is also due to the lower allowance prices under the approaches that involve the regulatory policies as these policies shift the burden on the regulated industries and off the non-regulated sectors of the economy.

Since the electricity sector plays a major role in abatement in most of the policy scenarios considered, we investigate the impact on the composition of the electricity generation mix. Figure 5 shows the electricity mix in 2030 and 2050 under each of the policy scenarios. Total electricity demand is reduced most significantly in both CAT50% scenarios as the GHG price and/or mandated technology adoption under regulation raises the marginal cost of electricity generation, leading to a reduction in total electricity demand.

The regulatory policies have mixed effects. The “Coal + RPS” and “Coal + CES” policies produce similar outcomes—a difference is that coal is reduced less in the RPS case in part because the policy is less stringent relative to the CES policy by 2050. The role of nuclear in the electricity sector declines in all cases between 2030 and 2050, as existing capacity is assumed in our model to be phased out amid a lack of public policy support for new construction. Wind electricity plays an important role in all scenarios that target the electricity sector, largely at the expense of coal. Natural gas continues to play a significant role in all policies, while the little remaining oil use in electricity is reduced under all policies (except for transport).

For the nation as a whole, electricity prices (shown in Figure 6) increase most under a cap-and-trade policy as the emissions price is reflected in the cost of electricity generation. An electricity policy only results in modest price increases as power producers shift to mandated and

Figure 6: Percentage change in electricity price by region (relative to "business-as-usual")



more costly generating technologies to comply with policy and the reductions required by the electricity policies modeled here prove to be smaller than under a cap-and-trade system. In the scenario that combines the cap-and-trade system and regulatory policies, the electricity price does not rise as much as it would under a cap-and-trade system alone. This is because the regulatory policies achieve some of the abatement that would otherwise need to be induced by a carbon price signal. In other words, because regulatory policies already require significant reductions through mandated technology changes, the sectoral burden of emissions reductions shifts, with electricity contributing only 34% of total reductions, relative to 44% under a cap and trade system with no regulatory policies. Reduced pressure on the electricity system means the electricity price increase will also be lower.

3.4 Welfare impact by region and income category

National welfare impacts and aggregate technology and emissions responses can mask significant regional variation. The regional incidence of policy can be an important determinant of policy support, and a detailed understanding of incidence can help to inform design of policy that addresses equity as well as efficiency concerns.

To explain variation in the welfare impacts across these categories we consider existing regional heterogeneity and detailed model forecasts of energy system characteristics under each policy scenario, and link changes in welfare to changes to energy prices, changes in the electricity mix, and region and income-specific electricity demand, vehicle ownership, and travel patterns.

3.4.1 Regional welfare impact

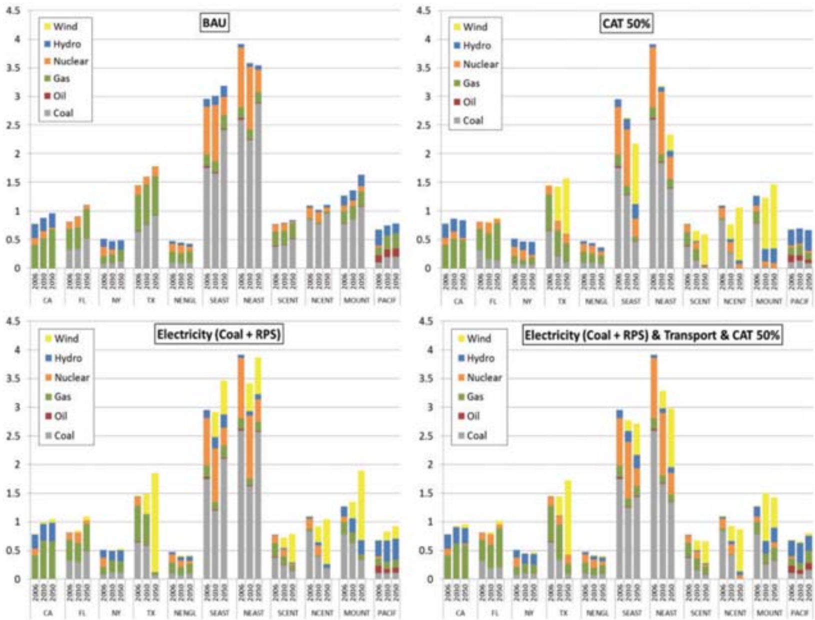
Table 5 summarizes the regional welfare cost expressed in both percentage of full income and in annual dollars per household. We find significant variation in costs across regions, which is reflected in the regional availability and cost effectiveness of abatement strategies. Comparing the cap-and-trade policy (CAT50%) with and without the regulatory policies, the per-household annual welfare impacts are larger and more negative under the combined policy case in every region except

Table 5: Net present value of equivalent variation of income by region

	CAT 50%		Electricity (Coal + RPS)		Electricity (Coal + RPS) + Transport		Transport		Electricity (Coal + RPS)		Electricity (Coal + CES)	
	%	*$/hh*	*%*	*$/hh*	*%*	*$/hh*	*%*	*$/hh*	*%*	*$/hh*	*%*	*$/hh*
NY	1.1	794	2.2	1601	2.3	1690	2	1479	0.4	307	0.7	552
SCENT	1.1	707	1.3	788	1.9	1112	1	479	0.5	418	0.4	357
SEAST	0.6	341	0.8	414	1.2	592	0.3	65	0.6	434	0.7	377
NEAST	0.6	398	1.1	740	1.2	797	1	338	0.6	509	0.7	487
FL	0.6	177	1.3	659	1.4	617	0.6	189	0.8	545	0.9	464
NCENT	0.6	437	0.9	492	1.2	744	1	259	0.4	334	0.6	455
TX	0.5	334	0	72	0.5	324	−0.2	−157	0.2	320	0.3	321
MOUNT	0.4	252	0.6	103	0.9	229	1	235	0	−36	0.3	207
CA	0.2	82	1	593	1	549	0.9	562	0.3	163	0.6	456
PACIF	0.2	22	0.1	534	0.4	295	1	277	−0.5	−721	0	−118
NENGL	−0.3	−355	0.4	205	0.3	9	0.2	33	0.4	275	0.6	413
US	0.5	307	0.9	510	1.1	615	1	308	0.4	305	0.6	386

Note: Positive numbers show welfare losses; negative numbers show gains. NPV calculated using an annual discount rate of 4%. "%" refers to EV as percent of full income. "$/hh" refers to annual average of NPV of EV in 2005$ per household.

Figure 7: Regional electricity generation by source (EJ per year)



for the Texas and Mountain regions, which benefit from abundant and cost-effective wind resources. Within individual regions, there is not an additive relationship in welfare change across any of the policies considered here.

The extent of effects can be quantified by evaluating the regional impacts of policies alone and in combination and comparing them. For example, sum of the welfare changes due to the transport and electricity (Coal + RES) policies individually does not equal the welfare change under the policies combined— in some regions, the welfare impact under the combined policies is less (better) than additive (e.g., New York), while in other regions welfare loss is larger (worse) than additive (e.g., South Central).

Regional welfare impacts under the electricity policies can largely be explained by the region's starting grid mix and the cost and availability of clean alternatives (particularly wind), which are shown in Figure 7. Some regions are not strongly affected—regions with generally cleaner grids (California, New York, New England) need not undergo significant changes under any of the policy scenarios considered, and experience less welfare loss. Other regions, particularly those with substantial wind resources (Texas, South Central, North Central, Mountain), bring significant shares of wind generation online, largely at the expense of coal generation. The RPS policy, alone or in combination with a cap-and-trade policy, brings wind generation earlier to more regions where it is not economically viable under a cap-and-trade policy alone (California, Florida, and to some extent New York). In other regions, responses vary depending on the policy type and stringency, with electricity production in the Southeast and Northeast reduced substantially under a cap-and-trade system. However, these impacts are mitigated in a case where a RPS is combined with the cap. In the model new technologies face initial cost hurdles associated with ramping up production capacity and early stage development risks. Once these hurdles are overcome, cost-competitive technologies will be introduced into the new capital stock, assuming constant returns to scale. By encouraging early deployment of wind technology, low-cost wind capacity is available later on and can be scaled up without facing the large initial cost penalty in the period through 2050.

The impetus for these responses is captured in the regional electricity prices that emerge under each policy scenario. The largest price increases occur in the Southeast and Northeast (over 100% in 2050), while the electricity markets of New England and California are the least affected (in percentage terms). Different combinations of policies also produce regionally distinct price responses—a cap-and-trade system results in a decrease or very modest increase in electricity prices in New England and California, respectively, in 2030, reflecting each region's relatively clean grid mix. Electricity regulatory policies also result in only a modest price increase in these regions. However, in other regions (for instance, Southeast, and Northeast) regulatory and market-based policies require significant changes in the grid mix relative to business-as-usual, which is reflected in electricity price increases that are much larger, particularly in the cap-and-trade policy scenario, as advanced electricity technologies remain costly in the absence of early deployment that would bring down costs over time.

To explain welfare losses associated with the transport policy, it is necessary to consider how the policy affects vehicle and fuel costs as they interact with diverse household preferences for vehicle ownership, efficiency, and driving. As shown in Table 7, household expenditures devoted to vehicle transport as a percentage of total transport expenditures vary significantly across both regions and income categories. Regional differences can be related back to the local availability of alternatives to vehicle travel, as well as regional income, residential density, and road infrastructure, and are captured in the base year data set and initial share parameters.

When explaining welfare losses due to transport policy (shown in Table 5), it is important to recognize that the welfare loss is always expressed relative to the counterfactual, and so the degree of fuel efficiency improvement in the reference scenario is an important determinant of regional welfare loss under policy. Large welfare losses in New York (-2%) can be explained by the fact that relative to the reference scenario, vehicles sold in New York must realize significant increases in fuel economy to achieve policy compliance. Given that a relatively large fraction of total passenger travel in New York does not occur in vehicles (47% for lowest income category) an increase in fuel prices (which in the reference results from increasing resource scarcity) would also significantly impact energy demand by purchased modes, which are not covered under the policy. A fuel economy standard instead forces fuel conservation to be achieved through vehicle fuel efficiency, while use of refined oil in other sectors is indirectly subsidized. Significant welfare losses also occur in New England, North Central, Mountain, and Pacific States (all 1.0%), given the large changes induced by the standard. Fuel economy improvement under the different policies is shown in Table 8. The table shows how the transport policy results in fuel economy improvements far in excess of those that occur with a cap-and-trade system as part of a comprehensive economy-wide GHG reduction program.

In all three policy scenarios, motor gasoline prices by region change significantly in 2030 relative to 2006. By raising the cost of gasoline proportional to carbon content, a cap-and-trade policy discourages refined oil use, leading to both lower price (net of the carbon change) and demand. This downward price pressure is even stronger under the transport policy (fuel economy standard), largely because the transport policy displaces significantly more oil demand than the cap-and-trade system. While there is a relationship between the price change and the regional welfare loss, the price signal captures many potentially offsetting forces acting on the supply-demand balance, such as the household reliance on vehicle use, mode substitution potential, and different initial prices by region, and so price changes do not by themselves explain the welfare outcomes (shown in Figure 9).

Figure 8: Percentage change in net present value of equivalent variation by income

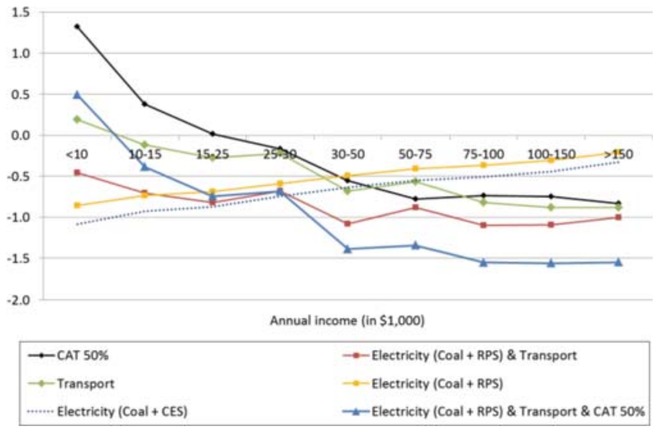
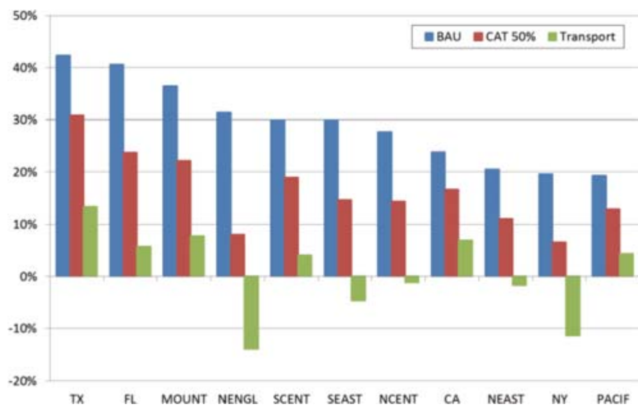


Figure 9: Percentage change in motor gasoline prices by region relative to 2006



3.4.2 Welfare impact by income category

An important question for policymakers is whether policies are regressive or progressive across income groups. We examine the impact of five of the above policies across nine income groups in the USREP model. We find the cap-and-trade and fuel economy policies to be moderately progressive, but the two electricity policies yield regressive welfare outcomes (see Figure 8). The results in the cap-and-trade case can be largely explained by the fact that revenue from the cap-and-trade policy is returned to households as a per-capita lump-sum transfer, while the owners of capital, concentrated in the higher income categories, must bear the costs of retrofitting or replacing capital to achieve policy compliance.

Electricity policies have a regressive effect. Poorer households tend to spend a larger fraction of their budget on electricity for heating, cooking, and other residential use. If policy drives up electricity prices by imposing technology requirements on generation and distribution providers, the cost will be felt most acutely by low-income households. For a vehicle fuel economy standard, progressive welfare impacts are consistent with the intuition that many of the poorest households

Table 6: Per-household annual average of net present value of welfare cost by income group (in $2005)

Annual income group ($1,000)	Fraction of pop. (%)	CAT 50%	Electricity (Coal + RPS) & Transport	Electricity (Coal + RPS) & Transport & CAT 50%	Transport	Electricity (Coal + RPS)	Electricity (Coal + CES)
<10	7.3	−546	162	−188	−63	314	357
41562	4.4	−218	240	63	19	291	329
15–25	9.5	−95	285	180	54	312	354
25–30	9.8	79	318	238	71	338	389
30–50	14.3	300	581	673	315	356	422
50–75	19.9	598	549	805	327	336	426
75–100	13.5	637	755	1034	555	318	432
100–150	12.8	691	753	1076	642	239	369
>150	8.5	956	772	1261	778	136	281
All		307	510	615	308	305	386

Note: Positive numbers show welfare losses; negative numbers show gains. NPV calculated using an annual discount rate of 4%.

do not own vehicles or own used vehicles, which are not directly affected by the fuel economy standard (which focuses on new vehicles). The relative emphasis households in each region and income category assign to purchased relative to own-supplied (vehicle) modes is captured in Table 7, which also shows the average share of household expenditures on vehicle transport by region and income. Wealthier households tend to own more vehicles and also drive them more. Households with higher incomes are also likely to include more members and thus to own more vehicles and travel more, leaving them potentially more affected by a vehicle price increases. With combined electricity and transport policies, poor households shoulder a disproportionate burden of electricity policy costs while wealthier households more acutely feel the impact of higher vehicle prices. The combined electricity and transport policy still yields a mildly progressive effect.

A comparison of the annual average net present value of welfare loss by income category under each of the policy scenarios is shown in Table 6.

4. TOP-DOWN VS. BOTTOM-UP REPRESENTATION OF THE ELECTRICITY SECTOR

The current research paradigm for ex-ante carbon policy assessment mainly involves two classes of models (see, e.g., Hourcade et al., 2006, for an overview). On the one hand, technology-rich "bottom-up" models provide a detailed representation of generation technologies and the overall electricity system. On the other hand, economy-wide "top-down" models represent sectoral economic activities and electricity generation technologies through aggregate production functions. While these models are designed to incorporate general equilibrium effects, the use of smooth functions is not well-suited to capture the temporal and discrete nature of technology choice.[10]

This section explores the implications of alternative structural models for the electricity sector. We compare two versions of USREP: a version that is based on a "top-down" representation

10. In addition, top-down representations of the electricity sector violate basic energy conservation principles outside of the benchmark calibration point (see Sue Wing, 2008).

Table 7: Mode shares and household expenditure share on vehicle transport (base year 2006)

	Share of household miles traveled by household owned vs. purchased transport									Average share on vehicle transport by region
	Income class									
	< 10	10–15	15–25	25–30	30–50	50–75	75–100	100–150	> 150	
CA	74.2	78.6	84.8	72.8	87.7	80.7	82.9	84.6	80.3	4.9
FL	82.8	85.9	85.8	78.9	91.4	87.2	90.6	89.8	86.8	9.6
NY	52.8	75.3	75.9	66	84.2	79.5	80.3	82.8	78.6	11.5
TX	83.1	91.3	94.7	87.6	97.5	98.6	98.9	100	100	6.6
NENGL	78.6	87.1	93.2	77.5	87.9	82.3	89.1	86.8	84.6	12.1
SEAST	80.7	86.1	91.6	81.6	92.9	88.2	91.8	90.5	89.4	9.9
NEAST	79.1	83.4	86.1	77	90.5	85.4	87	86.5	86.2	13.6
SCENT	85.9	92.7	96.5	81.1	95.4	94	98.2	95.6	95.4	10
NCENT	84.3	90.9	82.7	78	92.2	88.7	89.7	91.7	92.5	13.6
MOUNT	74.2	87.8	92	76.9	92.4	86.9	92.9	89.9	90.2	12
PACIF	84	94.8	79.8	72	87.8	83.6	90.3	82.7	84	11.7
U.S.	6.2	8.4	10.5	6.3	13	10.2	12.8	12.1	11.1	10.8

Note: Authors' own calculations based on U.S. Department of Transportation (2009). Average U.S. expenditure share on vehicle transport by income class.

of electricity—and that has been used for the analysis in the previous sections—with a version that features a detailed linear programming "bottom-up" load dispatch and capacity expansion model of the electricity sector. Our comparison focuses on the electricity-only policies, i.e. "Electricity (Coal + RPS)" and "Electricity (Coal + CES)".

While both modeling paradigms have been shown to produce similar results when focusing on conventional fossil-based electricity generating technologies, there exist significant differences in terms of how large-scale electricity generation from intermittent renewable energy sources is represented. We aim to obtain first insights into the question to what extent a relatively parsimonious "top-down" specification of the electricity sector can capture relevant key features of a structurally explicit "bottom-up" approach.[11] More specifically, our analysis will focus on the following questions: How do both models compare in terms of electricity generation fuel mix? Do the models roughly agree with respect to the projected role of renewable energy under aggressive renewable energy policies for the electricity sector? How are electricity prices impacted? What are the implications for economic costs of de-carbonizing the electricity sector both at the aggregate and regional level?

Our comparison is motivated by the fact that many modeling groups (e.g., USREGEN, NewEra, and ADAGE in this special issue) have recently undertaken substantial efforts to integrate a "bottom-up" electricity sector model within a large-scale CGE model.[12] However, we are not

11. Of course, if one is interested in model projections that provide very high resolution in terms of, for example, spatial, temporal, and technology dimensions, a detailed "bottom-up" approach may be more appropriate.

12. The integration of bottom-up technology representation and economy-wide interactions into "hybrid" models is the subject of a large literature. For example, reference is often made to "soft-linked" models, where the combination of the two models either fail to achieve overall consistency (Hofman & Jorgenson, 1976; Hogan & Weyant, 1982; Drouet et al., 2005; Jacoby & Schäfer, 2006), or complement one type of model with a "reduced-form" representation of the other, thereby lacking structural explicitness (Messner & Schrattenholzer, 2000; Bosetti et al., 2006; Manne et al., 2006; Strachan & Kannan, 2008). An alternative and more recent approach, referenced to as "hard-linked", is to directly embed a set of discrete generation technologies into a top-down model (Böhringer, 1998; SueWing, 2006; Böhringer & Rutherford, 2008). Under this approach, however, the representation of technological detail significantly increases the dimensionality of the model, thus severely constraining large-scale applications. Finally, a decomposition algorithm by Böhringer & Rutherford

Table 8: New (zero- to five-year-old) vehicle on-road fuel economy over time (miles per gallon)

	BAU				Transport			CAT 50%		
	2006	2030	2050	Compound annual growth rate 2006–2050	2030	2050	Compound annual growth rate 2006–2050	2030	2050	Compound annual growth rate 2006–2050
CA	23.2	24	25	0.17	31.1	43.7	1.45	24.6	26.2	0.27
FL	25.9	27.4	29.5	0.29	36.6	53.5	1.66	27.8	30.5	0.37
MOUNT	24.3	25.6	27.2	0.25	33	46.8	1.5	25.9	28	0.32
NCENT	23.8	24.7	25.9	0.2	31.6	43.8	1.4	25.1	26.7	0.27
NEAST	23.4	24.2	25.1	0.16	31.5	43.9	1.44	24.7	26.2	0.25
NENGL	28.2	29.8	32	0.28	38.9	55	1.53	29.9	32.5	0.32
NY	26.6	27.6	29	0.20	36.5	51.5	1.52	28.1	29.9	0.27
PACIF	23.2	23.8	24.7	0.15	30.5	42	1.36	24.3	25.7	0.24
SCENT	23.5	24.5	25.7	0.21	32.3	46.2	1.55	25	26.9	0.31
SEAST	24.6	25.6	27.1	0.22	33	46.2	1.45	26	27.9	0.29
TX	22.2	23.6	25.3	0.29	30.7	44	1.56	24	26.1	0.36

Note: U.S. Department of Transportation (2009) and model forecast.

aware of any attempt in the literature that compares both modeling paradigms through a set of unified scenarios. While it is not possible to validate models used for ex-ante policy analysis, we believe that such a comparison can offer insights into the relative strengths and weaknesses of each approach.

4.1 A "Top-Down" CGE Approach to Modeling Large-Scale Renewable Electricity Generation

The top-down approach to modeling electricity generation in energy-economy CGE models involves a representative firm that minimizes production costs subject to technological, institutional and resource constraints. Electricity generation, as any other production activity, is typically described by a nested constant-elasticity-of-substitution (CES) function that combines energy, capital, labor and intermediate inputs from other sectors. The CES nesting structure for electricity generating technologies listed in Tables 2 and 3 is described in Paltsev et al. (2005).

Here, we provide a sketch of our approach to modeling electricity generated from wind energy.[13] Using the "calibrated share form" (Rutherford, 1998), electricity generated by wind technology $n = \{$*Wind without backup, Wind with 100% natural gas backup, Wind with 100% biomass backup*$\}$, at time t in region r, $Y_{n,t,r}$, is in equilibrium determined by the following zero-profit condition:

$$p_{t,r} \geq \{\theta_{n,r}(\mu_{n,r} p_{n,w,t,r})^{1-\sigma_{n,r}} + (1-\theta_{n,r})(\mu_{n,r} p_{n,c,t,r})^{1-\sigma_{n,r}}\}^{\frac{1}{1-\sigma_{n,r}}} \perp y_{n,t,r} \geq 0 \tag{1}$$

where $p_{t,r}$ is the output price of electricity which is treated as a homogenous commodity. $p_{n,c,t,r}$ is a CES price index of energy, capital, labor, and other inputs. $p_{n,w,t,r}$ denotes the price of a fixed factor wind resource. $\theta_{n,r}$ denotes the benchmark value share of the fixed factor and $\sigma_{n,r}$ is the elasticity of substitution between the resource and non-resource inputs.

It can be shown that the own-price price elasticity of electricity supply generated from wind using technology n, $E_{n,r}$ is related to $\theta_{n,r}$ as follows (assuming a stable price for variable factors, i.e. $p_{n,c,t,r} \equiv 1$):

$$E_{n,r} = \frac{\partial \log Y_{n,r}}{\partial \log p_r} = \sigma_{n,r} \frac{1-\theta_n}{\theta_n}. \tag{2}$$

$\mu_{n,r}$ is a multiplicative mark-up factor that describes the cost of the first MWh of wind generated with technology n relative to a benchmark electricity generating technology, i.e. pulverized coal.

The resource input, $R_{n,r,t}$, is technology-specific, and is in fixed supply for any given period. Observations on penetration rates for new technology typically show a gradual penetration, for which there are numerous contributing factors. USREP replicates the penetration behavior that is

(2009) employs an iterative solution procedure to solve top-down and bottom-up model components consistently. This approach is essentially a soft-linked approach, but overcomes issues of dimensionality and consistency, and has been employed in the context of U.S. climate policy in Sugandha et al. (2009) and Rausch & Mowers (2012).

13. A similar logic could be applied to represent electricity generation from any other intermittent renewable energy source.

typically observed by endowing each regional economy with a small amount of a specialized wind resource. The endowment of this resource grows as a function of output $Y_{n,r,t}$ in the previous period:

$$R_{n,r,t+1} = f(Y_{n,r,t}, R_{n,r,t}, R_{n,r,0}). \tag{3}$$

Capacity expansion is thus constrained in any period by the amount of this fixed factor resource and the ability to substitute other inputs for it. As electricity generation from wind expands over time the endowment is increased, and it eventually is not a significant limitation on capacity expansion.

To characterize the wind resource by USREP region, we need to estimate for each region a pair $(\sigma_{n,r}, \mu_{n,r})$. We use high-resolution wind data from NREL's (2010) Wind Integration Datasets providing capacity factors and maximum output for wind turbines if they were located at sites across the U.S.[14]

For each potential wind site i, we execute a levelized cost of electricity model, described in Morris (2010), that calculates the levelized cost of electricity of using technology n on that site, $LCOE_{n,r,i}$. Based on an own-price elasticity formulation we use ordinary least-squares to fit:

$$\log(q_{n,r,i}) = \alpha + E_{n,r} \log(LCOE_{n,r,i}) + v_{n,r,i} \quad \text{if} \quad i \in r \tag{4}$$

where $q_{n,r,i}$ is electricity output, α is the estimated intercept, and $v_{n,r,i}$ is an error term. The logarithmic formulation means that the estimated coefficient $E_{n,r}$ is a (constant) price elasticity of supply. Exploiting the relationship in Eq. (2), we can incorporate estimated wind supply curves into the model.

The technology-specific markup-up factor is then given by:

$$\mu_{n,r} = \frac{LCOE_{n,r,min}}{LCOE_{bench}} \tag{5}$$

where $LCOE_{n,r,min}$ and $LCOE_{bench}$ denote the LCOE for the least-cost wind site and the benchmark electricity generating technology, respectively.

This deliberately simple approach is not without drawbacks. It has to rely on a strong assumption about back-up capacity for non-dispatchable renewable electricity generating technology. Marcontonini & Parsons (2010) point out that LCOE is not an appropriate metric for comparing the economics of renewable generation with the economics of non-renewable generation technologies that are dispatchable. An implicit assumption behind the LCOE is that each generation technology is designed to produce base-load power. The solution to this problem adopted in USREP is to evaluate a synthetic base-load technology created by combining wind generation capacity together with a 100 percent of back-up capacity, so that the combination is able to be dispatched and a base-load profile of production can be assured. The upshot of this approach is that it provides only an upper bound on the economic cost of renewable technologies implying that the renewable technology is at least as economic as will be evidenced by an LCOE incorporating back-up generation.

14. Identified sites take into account land use restrictions and make particular assumptions about turbine technology and density of turbine placements. The data set includes on- and offshore wind sites.

To partially address the issue of potentially overestimating the back-up cost of wind at lower penetration levels, we include a Wind without backup technology. Electricity generated from this technology is limited by employing a supply schedule that fits a constant elasticity supply curve through the following two points: (i) the least cost wind site and (ii) the cost for generating electricity with the Wind with natural gas backup technology at a level that corresponds to 5 percent of current levels of electricity generation in a given region. The "effective" supply curve of wind represented in the model is thus a combination of wind electricity generated with 0% back-up at lower output levels and with 100% (natural gas) backup at higher output levels.

Despite this flexibility, the fundamental shortcoming of the "top-down" approach—positing that wind electricity at large scales can only be generated with a 100 percent back-up capacity— still persists. While a more elaborated approach is likely to find that less than 100% back-up is needed, it has to make explicit the system costs associated with high penetration levels of wind including transmission and distribution costs, end-user/storage costs, and costs imposed by meeting various reserve requirements.

4.2 Integrating a "Bottom-up" Electricity Model in a CGE Framework: The USREP-ReEDS Model

The "bottom-up" version of the electricity sector is based on the National Renewable Laboratory's ReEDS (Renewable Energy Deployment System) model (Short et al., 2009). ReEDS is a linear programming model that simulates the least-cost expansion of electricity generation capacity and transmission in the contiguous U.S. ReEDS provides a means of estimating the type and location of conventional and renewable resource development, the transmission infrastructure expansion requirements of those installations, the composition and location of generation, storage, and demand-side technologies needed to maintain system reliability.

ReEDS provides a detailed treatment of electricity generating and electricity storage technologies, and specifically addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability and non-dispatchability of wind and solar power, and the influence of variability on curtailment of those resources. ReEDS addresses these issues through a highly discretized regional structure, temporal resolution, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

Rausch & Mowers (2014) embed the ReEDS model within the general equilibrium framework underlying the USREP model by employing a block decomposition algorithm put forward by Böhringer & Rutherford (2009). The virtue of this integrated approach is that electric-sector optimization—comprising electricity supply, and demands for fuels, capital, labor, and other inputs—is fully consistent with the equilibrium response of the macro-economic system—comprising electricity demand, fuel prices, and goods and factor prices. More details on the integrated top-down electricity model can be found in Rausch & Mowers (2014).

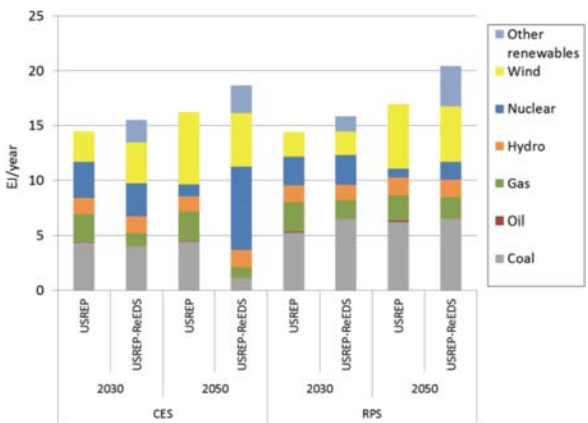
4.3 Model Comparison

Table 9 compares welfare costs, cumulative CO_2 emissions, and electricity price impacts obtained from the two alternative electricity models for each respective electricity-sector policy. Focusing first on the CES policy, the comparison suggests that both models produce roughly comparable net present value (NPV) welfare costs at the aggregated level. USREP with a "top-down"

Table 9: Model comparison of key variables

	USREP with "top-down" electricity sector		USREP-ReEDS model	
	RPS	CES	RPS	CES
Net present value welfare costs ($trillions)	1.64	2.08	0.91	1.97
Cumulative 2012–2050 CO_2 emissions reductions (%)	8.4	10.6	7.1	17
Electricity price impacts relative to baseline (%)				
Year 2030	6	7.3	0.7	5.3
Year 2050	4.7	10	7.1	13.6

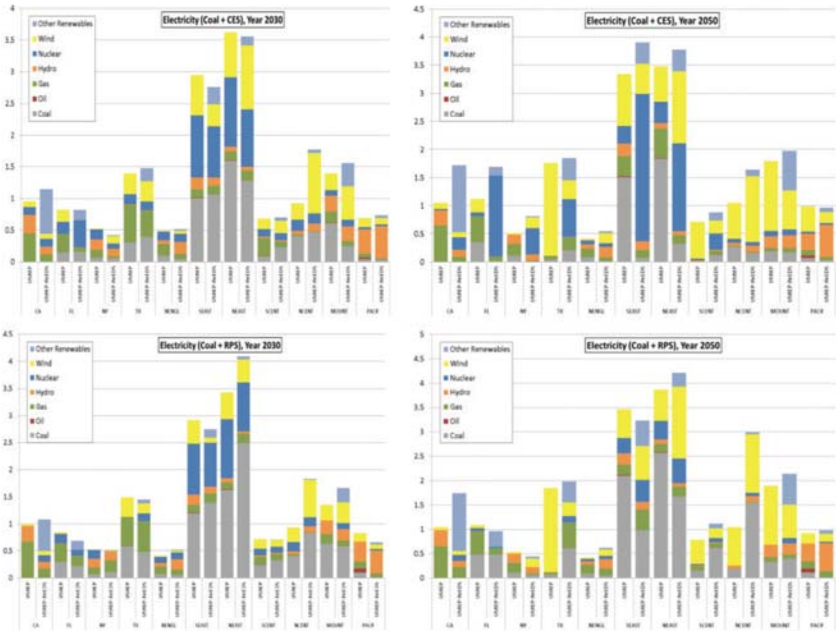
Figure 10: Model comparison of U.S. electricity generation by fuel



formulation of electricity estimates that NPV welfare costs of a federal CES policy are US$ trillion 2.08 whereas the USREP-ReEDS model suggests slightly lower costs at higher US$ trillion 1.97. Both models somewhat disagree on the amount of cumulative economy-wide CO_2 emissions reductions over the 2012–2050 period with the USREP-ReEDS model projecting about 16 Gt or about 50% higher emissions reductions. This can be explained by differences in the electricity generation mix shown in Figure 10. By 2050, the USREP-ReEDS forecasts that almost all coal generation capacity will have retired or be idle and a substantial fraction of electricity is generation from nuclear power; in the model with a "top-down" electricity sector, the expansion of nuclear is limited by a nuclear phase-out constraint that is part of the scenario assumptions of the EMF24 study.

Comparing electricity generation from renewable sources, it should be noted that the simplified "top-down" model only considers wind and biomass, while the USREP-ReEDS model includes all major renewable energy technologies including utility- scale photovoltaics (PV), concentrated solar power (CSP), and geothermal. These are represented by the category "Other renewables" in Figure 10. While the USREP-ReEDS model suggests slightly higher deployment of wind and other renewables in 2030, both models largely agree in 2050, with the "top-down" approach suggesting a level of wind energy that is comparable to the sum of wind and other renewables projected by the USREP-ReEDS model. Electricity price impacts projected by the two models are similar with the USREP-ReEDS model yielding slightly higher price impacts relative to the BAU baseline (13.6%) than the "top-down" model (10.0%) in 2050.

Figure 11: Model comparison of regional electricity generation by fuel



Differences between the "top-down" and "bottom-up" approaches become more apparent if one focuses on the RPS policy as this instrument targets only renewable energy technologies and rules out that "clean" fossil-based technologies and nuclear power can be used to meet the energy standard. Figure 10 shows that both modeling approaches project very similar levels of electricity generation from non-renewable energy sources and hydro by 2030 and 2050. While the projected amounts of wind electricity are again similar under both approaches, other renewables—which are not included in the "top-down" approach—contribute about 3.5 EJ (out of 20 EJ of total electricity production) in 2050 under the "bottom-up" approach. The inclusion of additional flexibility to meet the RPS translates into significantly lower estimates of economic costs associated with the RPS policy: if the "bottom-up" approach is used, NPV welfare costs are 44% lower as compared to the "top-down" CGE representation. Finally, both models produce similar projections in terms of CO_2 emissions reductions under the RPS policy case. Figure 11 compares the regional electricity generation mix by fuel across both models. Several points are worth noting.

First, while—not surprisingly—both approaches predict a somewhat different picture in terms of the regional electricity generation mix, for most regions the differences remain relatively small thus being consistent with the fact that national-level results have been found to be largely similar. Focusing on electricity from wind only, relatively large disagreements between both models only exist for the NCENT region in 2030 and for the NEAST, NCENT, and TX in 2050. Second, other non-wind renewables play a relatively modest role—with the exception of CA which deploys significant amount of geothermal and solar power in the USREP-ReEDS model by 2050—in terms of the electricity generation mix (not for costs as was noted above). Third, both models are relatively similar by 2030 but differences are more pronounced in 2050. Fourth, both models also produce a somewhat different picture in terms of fossil-based electricity generation among regions.

In summary, we conclude that the "top-down" approach produces very similar national-level welfare costs and electricity generation mix for the CES policy compared to the more tailored "bottom-up" approach. Discrepancies among both approaches for the RPS policy case are largely due to the fact that the "top-down" model does not consider other, non-wind renewable energy technologies. These could be easily added to the model following a similar approach as for wind, and would therefore likely bring cost estimates from both approaches more in line. At the regional level, the two approaches are largely consistent in terms of where significant investments in wind capacity/generation will occur. For a few regions, projections across both approaches yield discrepancies with respect to the electricity generation mix suggesting that a simplified "top-down" approach does not adequately describe the relevant "bottom-up" constraints in these regions.

We believe that this exercise has provided some first evidence that a parsimoniously specified "top-down" approach to modeling electricity generation can provide results that are, at least at the aggregated level, consistent with those obtained from a structurally more explicit "bottom-up" approach. As this depends on how well the responses of a CGE model would be calibrated to those from a bottom-up model, one can of course not generalize this finding to any generic top-down model. However, this rebuts to some extent the criticism put forward by modelers arguing that the lack of detail in "top-down" CGE models to represent critical features of the power system, especially with respect to large-scale intermittent renewable electricity generation, makes these models an inappropriate tool to study these issues.

5. CONCLUSIONS

This paper has investigated both the efficiency and distributional impacts of a representative set of climate policy scenarios under consideration in the United States, developed as part of the EMF24 modeling exercise. This paper moves beyond the canonical result that market-based instruments produce superior welfare outcomes to examine in detail the distributional impacts of a range of policy options. We apply an empirically-calibrated model of the U.S. economy with disaggregated regions and income categories, and with a rich description of the energy system including advanced technology detail. We further include a sensitivity analysis that provides initial evidence of the robustness of model outputs to the inclusion of technology and market detail at various levels of resolution.

The market-based instrument we model, a cap-and-trade system, yields superior welfare outcomes and also provides an effective mechanism for reducing the distributional impacts. The cost advantage can be directly traced to abatement flexibility across gases, sectors, technologies, and time, and is reinforced by the ability to recycle revenues as lump-sum transfers to households on a per-capita basis. Relative to a cap-and-trade system, regulatory policies are highly constrained in terms of the abatement opportunities available and the time frame on which these opportunities can be pursued. Even if limited flexibility provisions are added to regulatory policies, low cost opportunities are still limited by the policy scope. A fuel economy policy for new light-duty vehicles that introduces credit trading across manufacturers and extends banking and borrowing provisions will not change the fact that petroleum or emissions can only be reduced through measures that raise vehicle efficiency. The marginal costs of reducing electricity or transport emissions quickly exceed the marginal cost of reductions that would be incentivized under an equivalent cap-and-trade system. The flexibility and revenue redistribution potential under a cap-and-trade policy is a powerful advantage.

Regional variation in welfare impacts is significant, both across regions for a given policy and across different policies. Our results suggest that welfare impacts are more evenly spread under the cap-and-trade policy, given that reductions are spread across many sectors and as such do not unduly burden regions based on their relative advantages and disadvantages in terms of abatement costs and opportunities. Revenue recycling also helps to reduce burdens across all regions in the cap-and-trade case. By contrast, some regions are limited in their ability to respond to mandates that require action by sector or technology and thus face high costs, if these policies encourage costly reductions that would not have otherwise been pursued. This analysis underscores that regulatory policies can exaggerate the difference between winners and losers, by focusing on action in particular sectors or technologies and sparing others, while a cap-and-trade system calls forth action (albeit perhaps less aggressive) from across the economy and energy system.

In terms of variation in policy impact across income groups, our analysis finds that an electricity policy is regressive, while transport and cap-and-trade policies are moderately progressive. It is plausible that a transport policy (the only one of the policies we consider that is currently implemented at the national level) may be politically attractive because of its progressive nature and the fact that it exerts downward pressure on gasoline prices. These price reductions hide the true cost to households of efficiency improvements required, and improved fuel efficiency encourages consumers to drive more rather than less. Evidence of the regressive nature of electricity policies, by contrast, may discourage their broader acceptance.

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Impacts of Technology Uncertainty on Energy Use, Emission and Abatement Cost in USA: Simulation results from Environment Canada's Integrated Assessment Model

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ABSTRACT

To what extent could various technological advancements in the coming decades potentially help greenhouse gas mitigation in the U.S.? What could the potential contribution of end-use technology and other key clean electric energy technologies such as CCS, Nuclear power, wind & solar, and biomass be? This paper presents simulation results from an Integrated Assessment Model that suggest that, in the absence of policy measures, even under the most optimistic state of technology development and deployment scenarios, the U.S. energy system would still be dominated by fossil fuels and GHG emissions would increase significantly between 2010 and 2050. A pessimistic scenario in end-use technology would result in increased electric and non-electric energy use and GHG emissions compared to the advanced technology scenario, while a pessimistic scenario in any one of the four clean technologies examined would result in reduced electric and non-electric energy use and a small increase in GHG emissions. However, if all technologies are in pessimistic status, GHG emissions would increase significantly as more fossil fuels would be used in the energy system. Technology alone cannot achieve the abatement levels required. A market-based policy targeting the reduction of U.S. GHG emissions to 50% below 2005 levels by 2050 would result in dramatic decrease in coal-fired generation. With abatement policies in place, favorable technology scenarios reduce abatement costs and facilitate the energy system transition from fossil fuels to clean energy.

Keywords: Energy use, Clean technology, GHG abatement, Abatement cost

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1. INTRODUCTION

Historically energy use and economic activity level have been tightly coupled, and energy use is a vital and indispensable ingredient of economic growth (Toman and Jemelkova 2002; Stern and Cleveland 2004; Guttormsen 2009). However, energy production, energy transformation and energy use, in particular the combustion of fossil-fuels results in energy-related greenhouse gas (GHG) emissions, which accounts for the majority of anthropogenic GHG emissions. For example, in 2009, the total GHG emissions excluding land use change in the U.S. are some 6608 MTCO2e, of which 87% are energy related.[1] The United States Energy Information Administration (EIA)

1. For detailed information, please refer to website, http://cait.wri.org/.

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forecasts that in the absence of new policies, fossil fuel use will still dominate primary energy use in the U.S. in 2035 (US EIA 2011a and 2011b).

The scientific evidence confirms that increasing anthropogenic GHG emissions is an important contributor to global warming (Farley 2008; IPCC 2001, 2007). Actions by all large emitters in the developed and developing countries are necessary for meaningful global GHG reductions. In the absence of policy change, "the overall costs and risks of climate change will be equivalent to losing at least 5% of global GDP each year, now and forever and if a wider range of risks and impact is taken into account the estimates of damage could rise to 20% of GDP or more" (Stern 2006). The future path of emissions growth and the abatement costs under climate policy would heavily depend on the status of end-use technology and clean technologies as these can heavily influence the way energy is produced and used.

However, there is a high degree of uncertainty around the evolution of the future energy system. To explore how different factors might influence the evolution of the energy system and GHG emissions, we focus on the possible future development status of five key technologies: (1) end use technology, (2) CCS technologies, (3) nuclear energy, (4) wind & solar energy, and (5) biomass electric energy. The possible technology scenarios analyzed in this paper were identified in a model comparison exercise undertaken by the Energy Modeling Forum (EMF 24 U.S. Scenarios: Final version, 2012). To assess the role of uncertainties, this paper considers two extreme scenarios for each technology category; optimistic or high status and pessimistic or low status. Technology parameter values are applied in simulation exercises employing Environment Canada's Integrated Assessment Model (EC-IAM). To understand the role of technology in energy development and consequent emissions pathways, the model is calibrated to several baseline scenarios based on differing mixes of technology development and then policy simulations are performed for each baseline projection.

The rest of the paper is organized as follows: Section 2 provides a brief overview of the EC-IAM model. Section 3 presents the simulation results and Section 4 discusses the main findings and conclusions.

2. OVERVIEW OF EC-IAM

Environment Canada's Integrated Assessment Model (EC-IAM)[2] is based on the structure of the Model for Evaluating the Regional and Global Effects (MERGE) (Manne 1976; Manne and Richels, 1992; Manne et al, 1995; US Climate Change and Science Program, 2007). Modifications specific to EC-IAM include the explicit representation of Canada as a model region with specific extensions to represent oil sands reserves that are central to the evolution of Canada's oil producing sector and electricity generation mix reflecting Canadian endowments (NEB 2011). EC-IAM is an intertemporal multi-regional global computable general equilibrium (CGE) model suitable for analyzing regional and global effects of climate policies. It integrates an economy-energy model consisting of a top-down macroeconomic submodel and a bottom-up energy supply submodel with an aggregate climate submodel into an integrated model system to quantify alternative ways to assess climate policies.

2. Integrated assessment model can be broadly defined as any model which draws on knowledge from research in multiple disciplines for the purpose of assessing policy options for climate change control (Weyant et. al. 1996). For a comprehensive survey of various integrated assessment model, see (Kelly et al, 1999).

2.1 Macroeconomic submodel

In each region production is aggregated to a single macro sector with a nested constant elasticity of substitution (CES) function transforming the price responsive inputs comprising capital, labour, electric energy and non-electric energy into a numeraire good. The representative agent's instantaneous utility function in each region is a CES function of consumption of macro good and the passenger transportation. Economic decision in the model is described by Ramsey-Solow paradigm. The representative agent in each region chooses intertemporal consumption, level of various modes of passenger transportation, saving and investment to maximize total discounted utility subject to an intertemporal budget constraint. Investment forms next period's new capital. Regions are linked through international flows treating the tradable goods as internationally homogeneous goods. Production, input demand and consumption and passenger transportation demand and instantaneous utility as well are all vintaged as "putty-clay" formulation. Population, labour and automatic energy efficiency (AEEI) improvement index are exogenously specified based on best available information. In "putty-clay" formulation, old vintages equal the survival part of last period depending on the depreciation rate.

The production of new vintage output (YN_{rt}) at period t in regions r is given by a CES function as follows:

$$YN_{rt} = A_{rt}[\theta_{rt}(KN_{rt}^{\alpha}LN_{rt}^{1-\alpha})^{\rho} + (1-\theta_{rt})(EN_{rt}^{\beta}NN_{rt}^{1-\beta})^{\rho}]^{1/\rho} \qquad (1)$$

Where KN_{rt}, LN_{rt}, EN_{rt} and NN_{rt} are respectively the inputs of new vintaged capital, labour, electric and non-electric energy at period t in region r, and A_{rt} is the reference production efficiency index.

The new vintaged instantaneous utility (UN_{rt}) of representative agent at period t in region r is given by

$$UN_{rt} = UREF_{rt}[\alpha_{rt}CN_{rt}^{\delta} + (1-\alpha_{rt})TN_{rt}^{\delta}]^{1/\delta} \qquad (2)$$

Where CN_{rt} and TN_{rt} are new vintaged consumption and passenger transportation at period t in region r, and $UREF_{rt}$ is the reference utility index.

The budget constraint for region r in period t implies that total macro production must satisfy the competing claims on resources including consumption (C_{rt}), investment (I_{rt}), energy costs (EC_{rt}), transportation costs (TC_{r}), non-CO2 abatement costs (AC_{r}) and net exports of the composite numeraire good ($NTXY_{r}$).[3]

$$Y_{rt} = C_{rt} + EC_{rt} + TC_{rt} + AC_{rt} + NTXY_{rt} \qquad (3)$$

The energy cost is determined by energy supply technologies described later. Passenger transportation services are provided by vehicles distinguished by 5 alternative technologies: (1) internal combustion engine, (2) plug-in hybrid electric, (3) full electric, (4) compressed natural gas, and (5) backstop (e.g. H2) vehicle.

There are a limited number of goods that are tradable; macro good, oil, gas and emission permit. Heckscher-Ohlin paradigm is assumed to govern the international trade. This implies that all tradables are homogeneous rather than the region-specific heterogeneous goods usually repre-

3. The competing claim can also from the non co2 abatement cost and market value of damage.

sented in by Armington (1969) specification. For each tradable good *i* and each period *t*, there is a balance-of-trade constraint, i.e., at a global level, net exports or imports for all regions must sum up to zero.

$$\sum_r NTX_{irt} = 0 \tag{4}$$

For an optimization, the regional discounted utilities are weighted by Negishi weights[4]. Thus, the objective function is a Negishi weighted global welfare (NWGW),

$$NWGW = \sum_t \sum_r NWT_r UDF_{rt} \log(U_{rt}) \tag{5}$$

Where NWT_r is the Negishi welfare weight and are updated iteratively according to the weights of regional consumption in the global consumption, UDF_{rt} is the utility discount factor.

The model is solved using sequential optimization of global discounted utility by iteratively updating Negishi weights (Rutherford 1999; Negishi 1972). It can be operated either in "cost-effectiveness" mode or in "cost-benefit" mode depending on the damage value of climate change is taken into account or not. Given the focus of the paper simulations in this paper are performed using the "cost-effective" mode.[5]

2.2 Energy submodel

The energy submodel consists of bottom-up representations of various energy supply and transformation technologies along with supply constraints for electric and non-electric energies based on Energy Technology Assessment (ETA) model (Manne 1976; Manne et al. 1995). Electric and non-electric energy supply in this submodel meet all energy demand in the macroeconomic submodel and incur energy cost from exploration, extraction and conversion.

Levelized costs are used to describe all electric (vintaged and non vintaged) and non-electric energy technologies whose advancement is assumed to be exogenous. The various electric energy technologies including fossil fuel and clean and/or renewables are shown in Table 1. The choices of these technologies are endogenously determined by the cost-minimization actions of agents with the climate policies taken into consideration. Extracted coal and gas can be used either for generating electric energy or directly used by the industry or transportation. However crude oil needs to be refined before it is used for electricity generation or by industry or transportation. Beside refined oil, there are two other liquid fuel supply technologies; biomass-based liquids and coal-based synthetic liquids as is shown in Table 1. Beside solid, gaseous and liquid fuels, a backstop technology such as H2 is also introduced to provide non-electric energy service to the industry and transportation, as is shown in Table 1.

In addition to the bottom-up cost configurations of energy technologies, there are a number of constraints introduced in technology deployments. These include expansion, contraction, capacity and component ratio constraints relevant to technologies or technology vintages based on experts' knowledge. For example, natural gas is limited to supplying 50% of the electric energy market and

4. For debate on the equity issue of Negishi weight, see Stanton (2011).

5. In the "cost-effective" mode, the feedback from climate change to economy, such as damage resulting from the GHG emission and climate change is not accounted.

Table 1: Energy Technologies of the model

Electric Technology	Vintaged
Hydro-electric power	No
Nuclear power	Yes
Coal-fired electric power without CCS	Yes
Oil-fired electric power without CCS	Yes
Gas-fired electric power without CCS	Yes
Coal-fired electric power with CCS,	Yes
Gas-fired electric power with CCS,	Yes
Wind generated electric power	Yes
Solar generated electric power	Yes
Biomass fired electric power	Yes
Other renewable generation (geothermal , waste, and other renewable generation)	No
Liquid fuel supply technologies	
Refined oil	
Biomass-based liquids	
Coal-based synthetic liquids	
Non-electric energy Technologies	
Coal for end use	
Gas for end use	
Liquid for end use	
Backstop fuel for end use	

of the non-electric energy market for each region; the technology of coal fired without CCS is limited to supplying 50% of the electric energy market in OECD regions; and existing intermittent solar and wind are collectively limited to 25% of the electric market; bio fuel production and coal for end use technology are limited by capacity constraint.

In a market economy representative agents make choices among all available electric and non-electric technologies to satisfy energy demand. Energy submodel is interlinked with macro-economic submodel. The maximization of discounted utility implies that energy costs are minimized conditional on the energy demand from the macro economy.

Energy related GHG emissions are directly related to the use of energy such as coal, oil and gas in the energy production or conversion, or in the end use of industrial production or transportation. Non-energy related GHG emissions and abatement costs are set exogenously based on US Environmental Protection Agency (EPA) estimates (EPA 2006 and EMF 21).

2.3 Climate submodel

Climate submodel is a reduced-form aggregate description of the climate system from GHG emission to GHG concentration to radiative forcing and finally to temperature change over the preindustrial level in 1750 (IPCC 2001; IPCC 2007; Manne and Richels, 2005). The global

Table 2: Scenarios setup

Technology Dimension							
	REF	**END**	**CCS**	**NUC**	**W&S**	**BIO**	**All**
End Use Technology	High	Low	High	High	High	High	Low
CCS	High	High	Low	High	High	High	Low
Nuclear energy	High	High	High	Low	High	High	Low
Wind & solar	High	High	High	High	Low	High	Low
Biomass	High	High	High	High	High	Low	Low
Policy Dimension							
Baseline	REF-BAU	END-BAU	CCS-BAU	NUC-BAU	W&S-BAU	BIO-BAU	ALL-BAU
Cap & trade 50%	REF-CAP	END-CAP	CCS-CAP	NUC-CAP	W&S-CAP	BIO-CAP	ALL-CAP

emission of each GHG gas is the sum of regional energy related emissions determined by the demand and supply of energy and non-energy emissions less abatement.[6]

The total stock of GHG emissions is determined by a distributed lag process to account for the inertia of the climate system represented by the decay in the lifetime of GHG gases and the accumulation of current emissions. Concentration of GHG gases in the atmosphere is determined by the total stock of GHG gases proportionally. The radiative forcing of GHG gases in turn is determined by the concentration of GHG gases. Following IPCC, the model assumes that radiative forcing of CO2 is proportional to the logarithm of CO2 concentration; radiative forcing of CH4 or N2O is proportional to the square root of CH4 or N2O concentration; and radiative forcing of F-gas is proportional to the F-gas concentration. Total radiative forcing of GHGs is the sum of radiative forcing of various GHG gases. Finally, equilibrium temperature is proportional to the aggregate radiative forcing and actual temperature increase from pre-industrial level is determined by a lagged response to equilibrium temperature.

3. SIMULATION SCENARIOS AND RESULTS

3.1 Scenario set-up

Based on different technology and policy dimensions, 7 baseline and 7 corresponding policy scenarios were designed (Table 2). As mentioned before, a total of 5 technology groups are considered and for the simulation each of these technologies are assumed to be either in high or low status as defined in Table 3.[7] Starting with a reference baseline scenario in which all technologies are in high status, 5 baseline scenarios are designed assuming one of the 5 technologies in low status and finally in the 7th baseline all technologies are considered to be in low status. The baseline scenarios reveal that energy supply, its composition and emission growth will depend on

6. For non-energy GHG emission and their abatement cost-potential, EC-IAM is based on the estimates provided by the Energy Modeling Form Study 21.

7. Please refer to EMF 24 U.S. Scenario-Final for the technologies set-up detail and Clark et al. (2008) for cost information for various advanced energy technologies. The technology scenarios apply to all regions of the world. All other technologies such as traditional electric technologies with fossil fuels, hydro, etc., and non-electric energy technologies, such as fossil fuels and even backstop H2 technology are not subject to variation.

Table 3: Definition of technology status

Technologies (represented by AEEI)	High	Low
End Use Technology	For OECD regions, AEEI = 1.1%; for Non-OECD regions, AEEI = 1.7%	For OECD regions, AEEI = 0.4%; for Non-OECD regions, AEEI = 1.0%
CCS	Unit generation cost decrease by half in 2050 compared with that in 2010	Unavailable
Nuclear	Unit cost of Generation decreases by 20% in 2050 compared with 2010	Phase out after 2010
Wind & Solar	Unit Cost of wind and solar generation decreases by half in 2050 compared with 2010	Cost in 2050 stay the same as in 2010.
Biomass	Unit cost of generation decreases by half in 2050 compared with 2010	Cost in 2050 stay the same as in 2010.

the technology development (Figure 1). Simulation of a single policy scenario is run on each of the 7 baseline projections. The policy scenario involves lowering GHG emissions to 50% below the 2005 levels by 2050 following a linear reduction path starting in 2012 by the U.S. and other OECD countries. Non-OECD regions are assumed to muddle through as per the Copenhagen pledges.[8] Each region meets its emission target by a domestic cap-and-trade.

3.2.1 Electric Energy

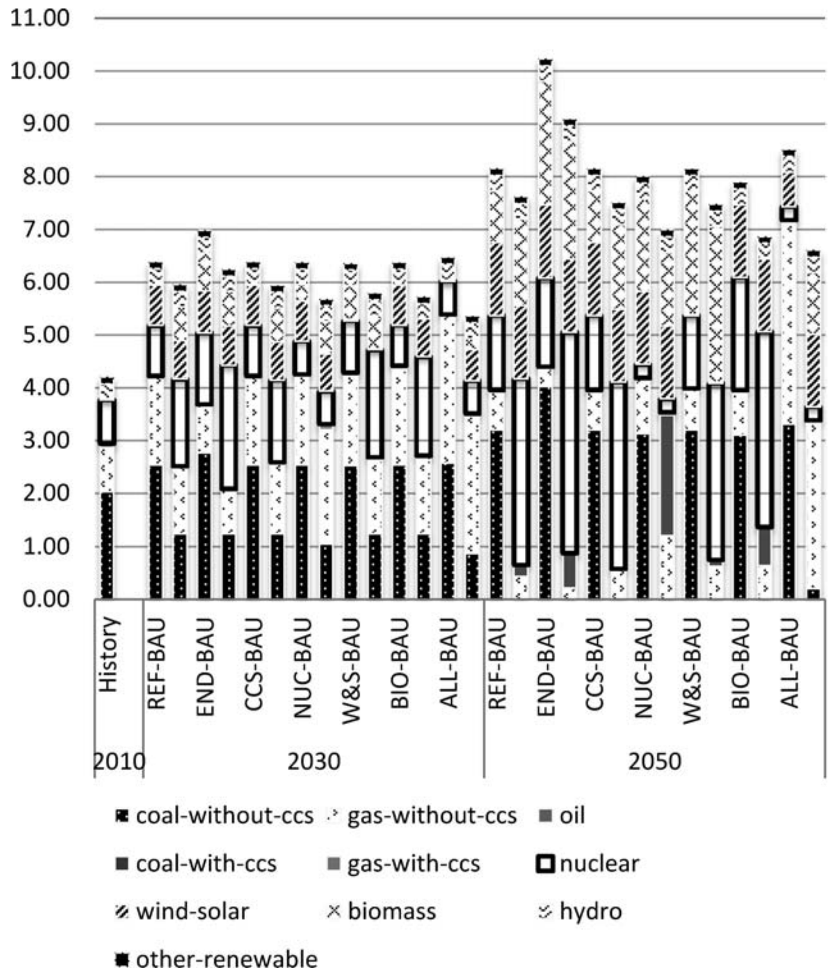
Figure 1 shows U.S. electric energy generation by source under different baseline and policy scenarios. The results indicate that in all scenarios U.S. total electric energy will continue to grow between 2010 and 2050. This is in sharp contrast with non-electric energy as discussed in the next section. Although, except in the worst status of technologies, the contribution of clean technology would increase as time passes, the conventional fossil fuel technologies would still dominate in U.S. electric energy generation in 2050. Compared with the reference baselines in which all technologies are assumed to be in optimistic status, in a baseline scenario in which the end-use technologies are in pessimistic status the supply of electric energy in the US would increase significantly. Electric energy supply would also increase compared to the reference scenario when all technologies are in pessimistic status and the contribution of fossil fuels would increase. A pessimistic scenario of one of the clean technologies would slightly decrease total electric energy generation. In policy scenarios, electric energy from coal-without-CCS technology would dramatically decrease and would not be viable in 2050. This would lead to increased generation from clean technologies. A policy scenario of pessimistic technology would lead to more reduction of total electric energy generation from their respective baselines compared with the best technological status.

3.2.2 Reference Technology

The reference baseline (REF-BAU) is the best technology case, where all technologies are in "high" status. In the baseline REF-BAU, total net electric energy generation by and large is

8. Further details on the scenario design are available in EMF 24 and EMF 27.

Figure 1: The U.S. electric energy generation (unit: TKWH)



Note: Please see Table 1 for notations used in Figure 1. Hydro and other renewable electric energy supplies are exogenously specified and assumed to remain constant in all simulations. Each CAP scenario, whose label does not show in the graph, follows BAU scenario with the same technologies. Also the same in Figure 2 and Figure 3.

expected to keep with the pace of economic growth in the future. Compared with 2010, the total net electric energy generation is projected to grow by more than half in 2030 and almost double in 2050 respectively. Generation from coal-without-CCS would still constitute the largest component up to 2050; the second largest component in total generation would be gas-without-CCS in 2030 and nuclear power in 2050. It is worth noting that wind & solar generation would enjoy rapid increase between 2010 and 2030, and nuclear power may have dramatic increase between 2030 and 2050. While biomass may be viable, the CCS technology although available, is not viable until 2050.

In the policy scenario (REF-CAP), total electric energy generation would decrease both in 2030 and 2050 compared to the reference baseline caused by a dramatic drop in generation from coal and gas without CCS in 2030 and complete exit of coal and decrease in gas-without-CCS generation by 2050. The major substitutive generation is from nuclear and biomass in both 2030 and 2050, and generation from coal-with-CCS would increase from null. Wind and solar generation shows little change, because the intermittent part of wind and solar hits or approaches limited proportion of total electric market, and the backstop part with storage of solar is still not competitive and thus not deployed.[9] In the presence of policy, conventional fuel technologies only make up a small part of the total generation which is being dominated by clean technologies.

3.2.3 Pessimistic End Use Technology

In the baseline scenario (END-BAU), compared with the reference baseline, total electric energy supply would be higher in 2030 and growing even more by 2050. The increase would come from biomass, nuclear, and coal-without-CCS (Figure 1). On the other hand, the generation form gas-without-CCS would decrease significantly because of the increased demand for gas in the non-electric energy market as will be discussed in the next section.

In the policy scenario with pessimistic end-use technology status (END-CAP) total electric energy supply would decrease in 2030 and 2050 compared to the baseline because of the reduction of generation from coal-without-CCS. Generation from gas-without-CCS would increase in 2030. Nuclear power would increase and become the largest component of total generation in 2030 and 2050. Generation from coal-with-CCS would also become an important contributor. The increase in generation from clean technologies is driven by policy-induced changes in electricity prices.

3.2.4 Unavailable CCS Technology

To understand the importance of carbon-capture and storage (CCS) in U.S. electricity generation, the analysis included a baseline scenario that assumes CCS technology is unavailable. While the baseline (CCS-BAU) is exactly the same as REF-BAU (because under the REF-BAU no CCS technology is deployed), the results of the respective policy scenario are different.

In the policy scenario with pessimistic CCS development (CCS-CAP) total electric energy would be lower in 2030 and 2050 compared to CCS-BAU because of the reduction of generation from coal-without-CCS. Generation from gas-without-CCS will also decrease slightly in both 2030 and 2050. Generation from nuclear and biomass would increase and become the major sources of total generation.

3.2.5 Nuclear Technology Phase out

This baseline scenario assumes nuclear phase out (NUC-BAU), i.e., no new nuclear power plant is developed after 2010. Under this scenario total electric energy would barely change in 2030 and decrease slightly in 2050. In both periods, the decrease of nuclear generation is almost fully offset by the increase of biomass generation.

In the policy scenario with nuclear phase out (NUC-CAP), total electric energy would decrease in 2030 and more in 2050 compared the baseline NUC-BAU. In 2030, generation from gas-without-CCS would increase by large amount and become the largest component of the total generation, and generation from biomass and gas-with-CCS would also increase. In 2050, generation from coal-with CCS would increase and become the largest component of total generation, and generation from gas-without-CCS and even gas-with-CCS would also increase.

9. Wind and solar have two parts: intermittent and backstop. The intermittent part is limited to given proportion while the backstop part is driven by its competitive strengths.

3.2.6 Pessimistic Wind & Solar Technology

In baseline W&S-BAU, compared with reference baseline, total electric energy supply would decrease slightly. The decrease of generation from wind & solar would be offset by increase of generation from gas-without-CCS, biomass and nuclear in 2030 and by biomass and gas-without-CCS in 2050.

In a cap-and-trade policy with a 50% emission reduction target in 2050 total electric energy would decrease due to the reduction of generation from coal-without-CCS. Generation from nuclear power would increase substantially and become the largest source of total generation. Generation from biomass would also increase substantially in both periods. In 2050, generation from coal-with-CCS and gas-without-CCS would also increase.

3.2.7 Pessimistic Biomass Technology

Under a pessimistic scenario for biomass-fired electricity generation, total electric energy would barely change in 2030 and decrease slightly in 2050 compared to the reference baseline. This implies that the contribution of biomass to total generation even with optimistic technology status is expected to be small. The decrease of generation from biomass in 2050 is offset by the increase of generation from nuclear.

If the cap and trade policy is in place under this scenario (BIO-CAP), total electric energy will decrease in 2030 and more in 2050 caused by the reduction of generation from coal-without-CCS. Generation from nuclear power would increase substantially and become the largest component of total generation in both periods.

3.2.8 All technologies in "Low" status

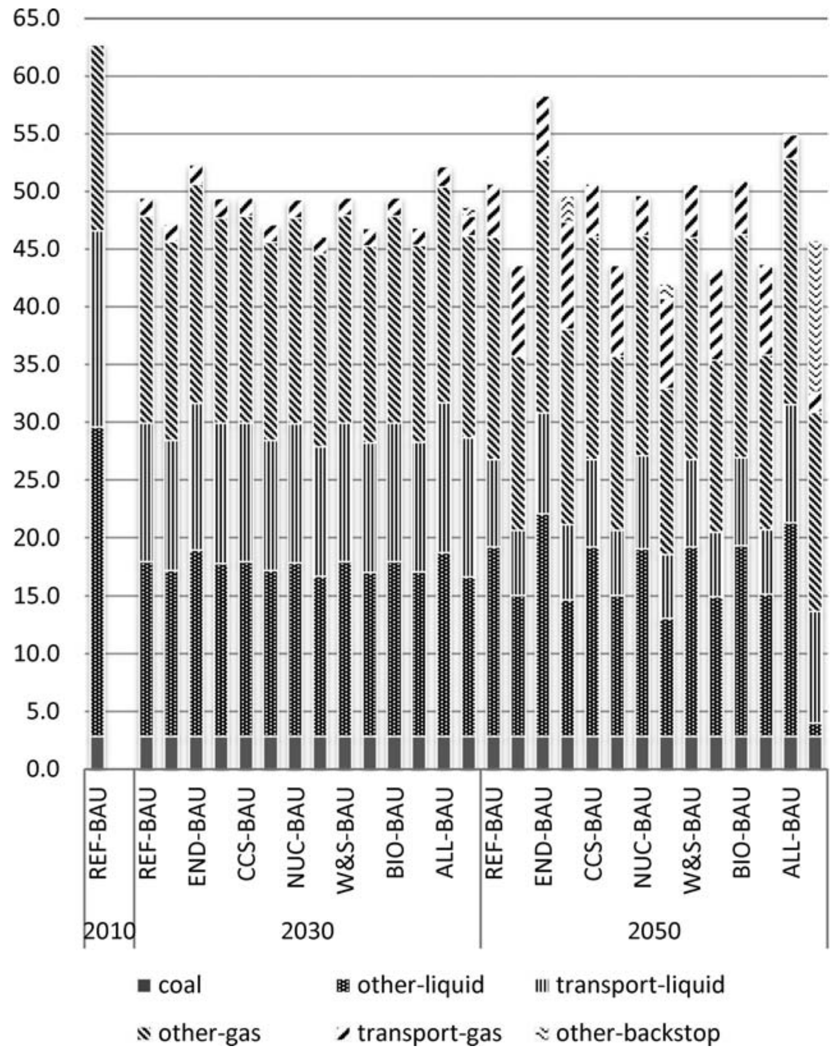
If all technologies are assumed to be in pessimistic or low status of development (ALL-BAU), total electric energy supply in the US would increase in 2030 and more in 2050. To meet the increasing demand, the decreasing generation from clean technologies would be met by increased generation from gas-without-CCS and to some degree by coal-without-CCS. The generation mix would shift sharply to conventional fossil fuel technologies.

The cap-and-trade policy under this scenario (ALL-CAP), would lead to decline in total electric energy generation in 2030 and even more in 2050 caused by the reduction of generation from coal-without-CCS. Generation from coal-without-CCS would not completely exit from the market. Generation from gas-without-CCS would be the largest component of total generation. Even in pessimistic status, supply from wind & solar and biomass would constitute 40% of total generation in 2050.

3.3 Non-Electric Energy

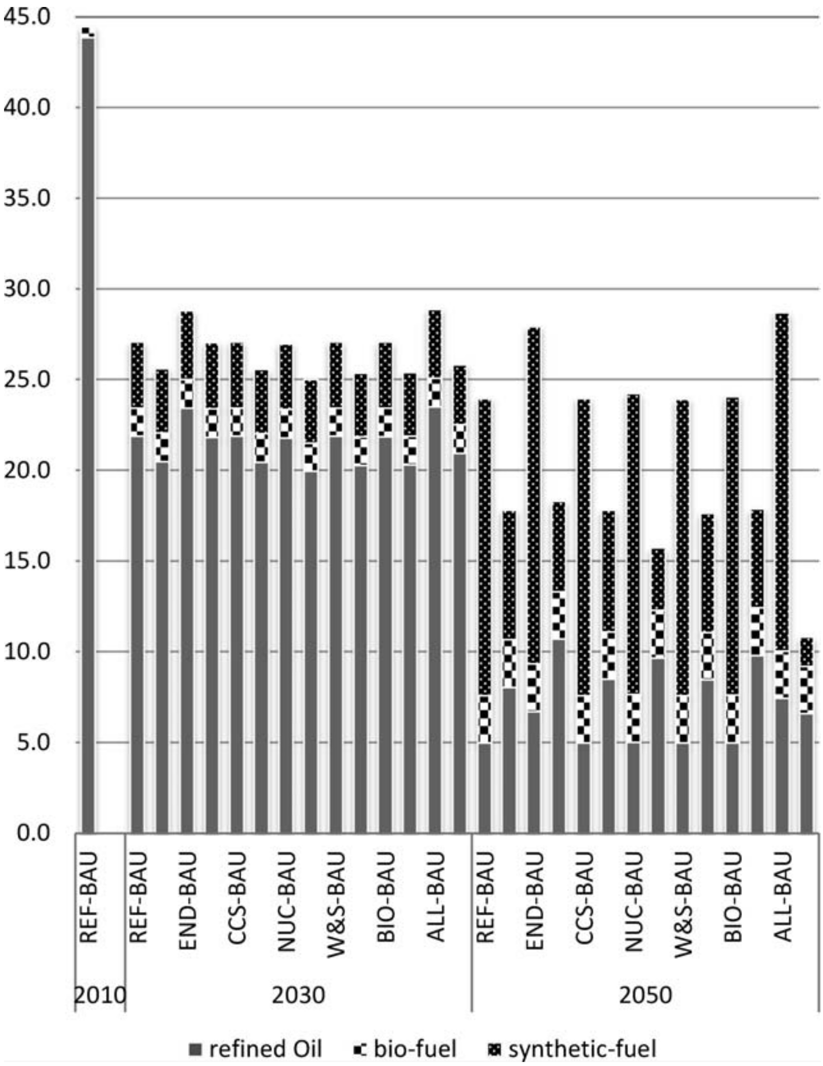
Figure 2 shows non-electric energy use for transportation and other industrial production, and Figure 3 presents the supply of liquid fuels under various scenarios. The results suggest that in all baselines total non-electric energy use would decrease a lot between 2010 and 2030 and increase only slightly between 2030 and 2050. Results also suggest an interesting structural change—a shift from liquid to gas use in the economy in all baselines. Correspondingly liquid supply would decrease continuously in the future, with a dramatic shift from refined oil to bio-fuel

Figure 2: The U.S. non-electric energy use (unit: EJ)



and coal-liquid synthetic fuel. Compared with the reference baseline of best technologies, a baseline with pessimistic end use technology development would lead to increased total non-electric energy use and liquid supply, a similar result to electric energy use. Baselines with pessimistic development in any one of the four clean technologies would lead to small changes in total non-electric energy use and slight decreases of liquid supply. A baseline in which all technologies are in pessimistic status would lead to increased total non-electric energy use and liquid supply. All policy scenarios reveal reductions in total non-electric energy consumption and more significant decreases of liquid supply especially in 2050. However, gas use in transportation would increase significantly in 2050 in all policy scenarios except that in which all technologies are in pessimistic status. In this scenario liquid supply would not only decrease, but also undergo interesting structural shift, from coal-to-liquid synthetic fuel to refine oil in 2050. Backstop fuels such as H2 would become viable in some policy scenarios.

Figure 3: The U.S. liquid supply (unit: EJ)



3.3.1 Reference Technology

In the reference baseline (REF-BAU), total non-electric energy use would decrease substantially between 2010 and 2030 and then increase between 2030 and 2050. This decrease is caused by the decreased liquid use in both transportation and non-transportation sector. In contrast, coal consumption is consistently low and gas use would increase in both transportation and other industrial sectors. Backstop fuels such H2, while available, are not deployed as they are not competitive. Total Liquid supply would decrease dramatically between 2010, 2030 and 2050. This is essentially due to a dramatic decrease in refined oil possibly because of heightened costs owing to incremental exhaustion of oil resource. Bio-fuel (biomass to liquid) would increase steadily, and synthetic fuel (coal to liquid) would be viable in 2030 and would be the top liquid supplier in 2050. Becasue of the deployment of coal to liquid technology, the total supply of liquid would only slightly decrease between 2030 and 2050. With increasing natural gas use, the total non-electric energy use would increase between 2030 and 2050.

Under the policy scenario (REF-CAP), total non-electric energy use would decrease in 2030 and further in 2050 essentially due to reduced demand for liquid and gas in other industry and liquid use in transportation. However, gas use in transportation would increase significantly in 2050. Total liquid production would decrease significantly in 2030 and 2050. Refined oil would decrease significantly in 2030 but increase in 2050, and coal-to-liquid would decrease dramatically in 2050.

3.3.2 Pessimistic End Use technology

Under the pessimistic end-use technology scenario (END-BAU), total non-electric energy use would increase between 2010 and 2050. Liquid and gas use in transportation and other industries would increase throughout the period.

If the cap-and trade-policy is implemented under this scenario (END-CAP), total non-electric energy use would decrease during the period. The decrease comes from liquid and gas use in non-transportation industry and liquid in the transportation sector. In contrast, gas use in transportation increases by a large amount by 2050. Total liquid production would decrease significantly in 2030 and 2050. Synthetic fuel production decreases dramatically in 2050 and refined oil decreases in 2030 but increases in 2050. Backstop fuels such as H2 become viable in non-transportation industry in 2050.

3.3.3 "Low" development of clean technologies

Baseline scenarios with low status in any one of the 4 clean technologies reveal similar results as in electricity generation—there are only very slight changes in the non-electric energy use and liquid fuel production.

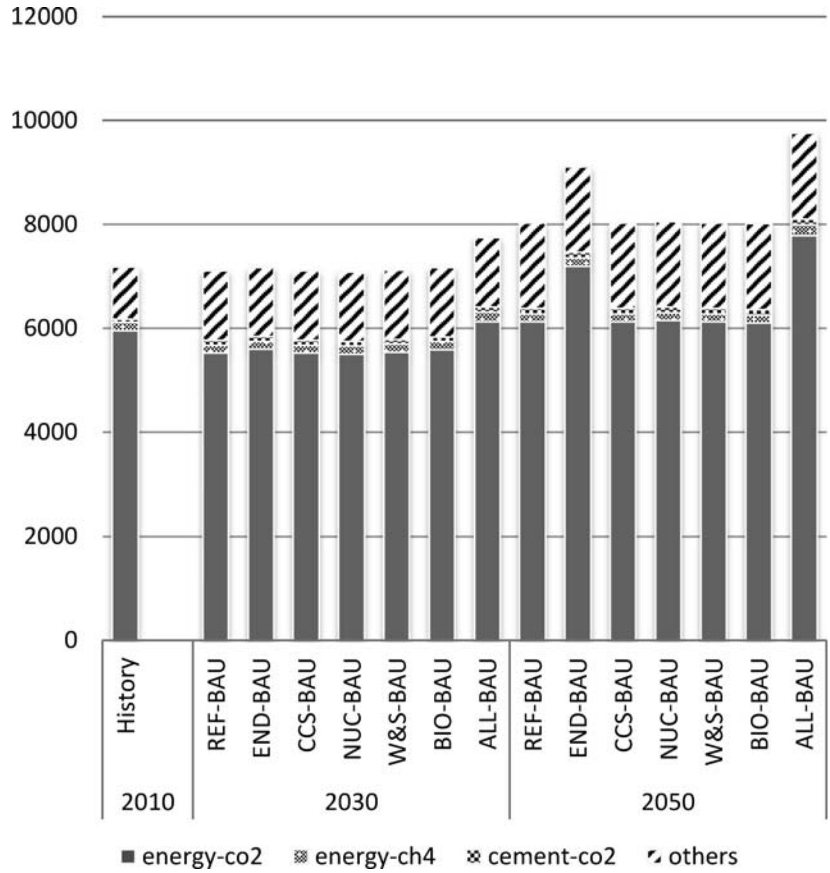
The implementation of the cap-and-trade policy around these baseline scenarios (CCS-CAP, NUC-CAP, W&S-CAP and BIO-CAP) also reveals similar patterns as in electricity generation. Liquid and gas use in industry and liquid in transportation sector would decrease significantly both in 2030 and 2050, in contrast, gas use in transportation would increase by a large amount in 2050. Synthetic fuel production decreases dramatically in 2050 and the production of refined oil decreases in 2030 but increases in 2050. If nuclear development is assumed to be in low status (In NUC-CAP), backstop fuels such as H2 would become viable in non-transportation sector in 2050.

3.3.4 All technologies in "low" status

When all technologies are in pessimistic status (ALL-BAU), total non-electric energy use would increase between 2010 and 2050 essentially due to increased energy demand by end use sector. Liquid use in transportation and other industry, and gas use in other industries increase while the use of gas in transportation decreases sizably in 2050. Total liquid production also increases in both periods and so do refined oil and synthetic fuel.

In the presence of cap-and-trade policy (ALL-CAP) total non-electric energy use decrease significantly in 2030 and 2050. The decrease comes from liquid fuel and gas use in other industry and liquid fuel in the transportation sector. Gas use in transportation also decreases slightly in both periods. Total liquid production would decrease significantly. Synthetic fuel production would de-

Figure 4: GHG emission in baselines (unit: MMT CO2e)



crease dramatically in 2050 and refined oil would decrease in 2030 but increase in 2050. Finally, backstop fuels such as H2 become viable in non-transportation industry in both periods.

3.4 GHG Emission Baselines

When looking at GHG emissions, we consider only the baselines, since all scenarios would have the same GHG constraints under the domestic cap & trade policy discussed earlier. Figure 4 shows US GHG emission in various baselines.

In the most optimistic technology scenario (REF-BAU) total GHG emissions in the U.S. would be slightly lower in 2030 and about 10% higher in 2050 compared to 2010. This is essentially due to the reduction of non-electric energy consumption and automatic energy efficiency improvements assumed in the baseline. Any pessimistic scenario with respect to technology development would lead to more GHG emissions, consistent with the energy use as discussed above. However, in all baselines except the scenario in which all technologies are in pessimistic status (ALL-BAU), total GHG emissions in 2030 would be slightly lower and in 2050 they would be higher compared to 2010. Under pessimistic end use technology scenario the U.S. GHG emissions would increase significantly, especially in 2050. The pessimistic scenario in any other clean electric technology would not change total GHG emissions much, which may be due to the fact that other clean electric technologies are in place to substitute for it in addition to the constraint assumed for coal-fired

Table 4: GHG Price in policy scenarios (unit: US $ in 2000 per tonne of CO2 eq.)

	2030	2050
REF-CAP	16	111
END-CAP	24	141
CCS-CAP	18	114
NUC-CAP	45	146
W&S-CAP	31	117
BIO-CAP	31	120
ALL-CAP	66	148

electricity mentioned in the earlier part of this paper. However, the status of technological development would significantly affect the abatement costs.

3.5 GHG Abatement price

Table 4 shows GHG price in per tonne of CO2 equivalent in various policy scenarios. In the scenario of best technologies (i.e. REF-CAP), GHG abatement prices are the lowest, $16 and $111 per tonne of CO2 equivalent in 2030 and 2050. Under the worst technology scenario (i.e. ALL-CAP), the GHG abatement prices are the highest, $66 and $148 per tonne CO2 equivalent in 2030 and 2050; GHG abatement prices in all other scenarios fall between those two extremes. While compared among the remaining single pessimistic technology scenarios (i.e., END-CAP, CCS-CAP, NUC-CAP, W&S-CAP and BIO-CAP) the GHG abatement prices are the highest in NUC-CAP and lowest under CCS-CAP. This indicates that the development and adoption of nuclear could significantly contribute to climate change mitigation costs. Interestingly there is not much difference in carbon prices required for the 50% cap in other policy scenarios particularly in 2050. For example, the carbon price range in these policy scenarios is $111—$120 per tonne of CO2 equivalent in 2050. This is essentially due to the presence of alternative clean technologies that can be substituted when one of them is in low status. For example, backstop technologies, especially H2 drives are to be substituted for non-electric energy use.[10] Similarly, there is not much difference between the carbon prices in REF-CAP and CCS-CAP scenarios due to available alternative technologies and the CCS costs. The comparison of results across scenarios suggests that the non-availability of nuclear power or its phase-out would make emissions abatement most expensive in 2050.

3.6 Economic Loss

Economic loss for the baseline scenarios is measured as percentage change in GDP compared to reference baseline (REF-BAU) while for the policy scenarios these are represented as percentage change in GDP compared to respective baselines (Table 5).

10. In our model, the backstop technology such H2 for non-electric energy use is also represented by levelized cost and is not subject to capacity constraint. The assumption of low technology status does not apply to this technology option. To explore the influence of the unavailability of this technology, we run another technology scenario with policy whose results are not reported in the text and in which all technologies are low plus the unavailability of this backstop technology. The results show the carbon price is as high as up to 500 US$ in 2050. That suggests the clean non-electric energy technologies also matter very much in the climate policy.

Table 5: Percentage change in GDP relative to reference baseline in baselines and relative to respective baselines in policy scenarios in 2030 and 2050

scenario	2030	2050
REF-CAP	−0.07	−0.49
END-BAU	−0.42	−0.46
END-CAP	−0.04	−1.00
CCS-CAP	−0.09	−0.50
NUC-BAU	−0.03	−0.06
NUC-CAP	−0.22	−0.88
W&S-BAU	−0.02	−0.03
W&S-CAP	−0.10	−0.54
BIO-BAU	−0.01	0.00
BIO-CAP	−0.13	−0.66
ALL-BAU	−0.53	−1.17
ALL-CAP	−0.54	−1.62

In the baseline scenarios, the economic loss in END-BAU is the highest among the baselines of single pessimistic technology, while in all other 4 baselines, economic loss is quite small. This indicates that the development of the end-use technology is the single most important contributor to costs savings. It is to be noted that if the development of the end use technology is in low status while all other technologies are in good status the emissions growth is the highest compared to the reference baseline scenario where all technologies are in good status. This is also reflected in policy costs. In the policy scenario that achieves a 550 ppm target, the economic loss is the highest in END-CAP and second highest in NUC-CAP and lowest in CCS-CAP among the 5 policy scenario with single pessimistic technology.

The economic loss or the costs to meet the 550 ppm goal under a cap and trade closely reflect the abatement prices under various policy scenarios discussed before. In the policy scenario with best technologies (i.e. scenario REF-CAP), economic loss is 0.06% and 0.49% of GDP relative to reference baselines in 2030 and 2050 respectively. In the policy scenario with the worst technologies, (i.e. scenario ALL-CAP), economic loss is 0.54% and 1.62% of GDP relative to reference baselines in 2030 and 2050 respectively. As seen before in case of carbon price, the policy costs for single technology variation is the second highest in NUC-CAP after END-BAU. The result for nuclear is understandable, nuclear power is currently one of the most competitive low carbon options (Tavoni et al 2012). Its phase out would impose huge costs unless other competitive technology is available.

It is difficult to compare results across studies due to differences in model structures, data, sector definition and coverage and available technology options. Luderer et al. (2012)'s findings suggest that renewables including biomass, as well as CCS are the most crucial technology options, while the option to expand nuclear beyond baseline levels is somewhat less important. Part of this result can be explained by the technology options. For example in WITCH model nuclear is a direct substitute of backstop electricity generation technology (Tavoni et al. (2012). Therefore when nuclear is constrained, advanced technology which is subject to innovation needs to be deployed.

4. SUMMARY AND CONCLUSIONS

The development and deployment of energy efficient and environmentally clean technologies can significantly reduce the burden of climate change mitigation policies. However, there are wide-spread uncertainties in technology development and its economically viable applications. In order to assess how technology uncertainties could affect the U.S. energy supply, energy mix, GHG emissions and abatement costs, this paper uses Environment Canada's Integrated Assessment Model (EC-IAM) to conduct projections based on various technology assumptions and performs policy simulations. The main findings of the paper can summarized as follows:

First, in the absence of climate policies even with best technology status the U.S. energy system, both electric and non-electric, would be dominated by fossil fuels even in 2030 and 2050. GHG emissions would increase significantly between 2010 and 2050. In the pessimistic end use technology scenario both electric and non-electric energy production and consumption would increase significantly. Fossil-fuel energy use in both electric and non-electric energy sectors would increase resulting in significant increase the GHG emissions. If one of the four clean technologies namely, CCS, nuclear power, winds and solar, biomass is in "low" status there would not be any significant change in total energy demand. However, if all five technologies are in "low" status, both electric and non-electric energy use would increase and the US energy system will shift far towards fossil fuels and therefore GHG emission would increase significantly.

In the presence of a cap-and-trade policy targeting GHG reduction to 50% below the 2005 level by 2050, the use of fossil fuels, especially coal-fired generation without CCS and coal-to-liquid synthetic fuel, would reduce dramatically and total electric and non-electric energy use consumption would decline. The US energy system would shift from the fossil fuels to clean energies such as nuclear, coal-fired electric energy with CCS, wind & solar and Biomass electric energy and even backstop non-electric energy such as H2 depending upon the status of technologies. In most scenarios natural gas use in transportation would increase significantly to offset decreased liquid use and refined oil would increase to offset decreased coal- to-liquid in 2050.

The state of technology development would significantly affect the GHG abatement costs. Depending upon the technology status the GHG abatement prices per tonne of CO2 equivalent lie between \$16 and \$66 in 2030, and \$111 and \$148 in 2050. Total economic cost in term of GDP for lowering the US emission to 50% below the 2005 level by 2050 would lie between 0.06% and 0.54% in 2030, and 0.49 % and 1.62% in 2050.

Two caveats for the exercise are in place, (1) only the variations of clean electric technologies and end use technology are considered in the simulations, the non-electric energy technologies and fossil fuel energy technologies are all set in the default optimistic status. If the uncertainty of these technologies especially the backstop H2 technology, are taken into consideration, the range of abatement cost may change. (2) The simulations are for the purpose of describing the uncertain world, cannot be used to prescribe for the purpose of technology policies.

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