THE IMPACT OF FUTURE CO_2 EMISSION REDUCTION TARGETS ON U.S. ELECTRIC SECTOR WATER USE

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Abstract

COLIN MACKAY CAMERON: The Impact of Future CO_2 Emission Reduction Targets on U.S. Electric Sector Water Use
(Under the direction of Dr. J. Jason West)

The U.S. electric sector's reliance on water makes it vulnerable to the impacts of climate change on water resources. Here we analyze how constraints on U.S. energy system carbon dioxide (CO_2) emissions could affect water withdrawal and consumption in the U.S. electric sector through 2055. We use simulations of the EPA's U.S. 9-region (EPAUS9r) MARKAL least-cost optimization energy systems model with updated water use factors for electricity generating technologies. Model results suggest CO_2 constraints could force the retirement of old power plants and drive increased use of low water-use renewable and nuclear power as well as natural gas CCS plants with more advanced cooling systems. These changes in electric sector technology mix reduce water withdrawal in all scenarios but increase water consumption in aggressive scenarios. Decreased electric sector water withdrawal would likely reduce electric sector vulnerability to climate change, but the rise in consumption could increase competition with other users.

Acknowledgements

I would like to thank my advisor Dr. J. Jason West for his advice, support and hours of assistance with this research. I would also like to thank William Yelverton, Rebecca Dodder, Carol Lenox, and Dan Loughlin for their patience, insight and generosity in teaching me to use the MARKAL model and guiding me through my research.

Table of Contents

List of Figures

Figure

List of Abbreviations

AEO 2012	U.S. Department of Energy Annual Energy Outlook 2012
CAIR	Clean Air Interstate Rule
CAFE	Corporate Average Fuel Economy
CCS	Carbon Capture and Sequestration
CO_2	Carbon Dioxide
EIA	Energy Information Administration
EPAUS9r	Environmental Protection Agency United States Nine Region Database
H.R.	U.S. House of Representatives
kWh	Kilowatt Hour
MARKAL	MARKet ALlocation energy systems model
MW	Megawatt
MWh	Megawatt Hour
NO_x	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
PJ	Petajoule
ReEDS	Regional Energy Deployment System
RPS	Renewable Portfolio Standard
SO_x	Sulfur Oxides
VMT	Vehicle Miles Traveled

I. Introduction

Over 90% of U.S. electricity supply is generated by thermoelectric power plants[25] that require an abundant supply of water for cooling. The electric sector withdraws more water than any other sector in the U.S.,[29] accounting for 41% of all freshwater withdrawals.[8] Electric sector water use also accounts for 6% of all water consumption in the U.S. and is expected to grow to 9% by 2030, making it the fastest growing water consumer.[1] This heavy dependence on water means the U.S. electric sector is highly vulnerable to changes in water resource availability; when cooling water supply is compromised, electricity generation may be reduced or shutdown.[9]

Thermoelectric cooling can be compromised in three ways. First, the water level of rivers and other cooling water sources can fall below the cooling water intakes of nearby power plants and thereby prevent those plants from withdrawing sufficient water for cooling. Second, high source water temperatures can reduce the efficiency of power plant cooling systems and consequently limit electricity generating capacity.[21] Finally, state regulations prohibit power plants from discharging heated cooling water into water bodies that already exceed temperature thresholds designed to protect water quality and ecosystems.[1] As a result, when water temperatures approach or exceed these limits, power plants must reduce or shut down power production.

Over the last decade, droughts and heat waves have compromised cooling water sources and disrupted power generation numerous times. One of the best-known incidents was a widespread drought and heat wave that affected the southeastern United States in August 2007. It forced multiple Tennessee Valley Authority (TVA) power plants, including the 3,297 MW Brown's Ferry nuclear plant, to temporarily curtail operations.[9] TVA was forced to buy power from neighboring utilities to meet electricity demand resulting in considerable cost increases to consumers.[31] Water limitations have forced similar power generation reductions at multiple sites throughout the United States[9] including as recently as August of 2012 at the Millstone Nuclear Power Station in Waterford Connecticut.[6]

These episodes are likely to become more frequent and more severe in the future as a result of climate change. Numerous climate modeling assessments have projected significant decreases in average low stream flows[17] and increases in average water temperatures[30] in many parts of the U.S. over the next 50 years. These changes are projected to be most severe in the southern and southeastern U.S. where river temperatures may exceed regulatory limits as often as 40 days per year and low stream flows could decrease by an additional 25% by 2040.[30] These changes have the potential to reduce total U.S. electric generating capacity by as much as 16% over the next 20 to 40 years.[30]

This vulnerability to climate change may be further exacerbated by increased demand for electricity and increased competition for water from other sectors in the future. The Energy Information Administration (EIA) projects the U.S. will consume over 27% more electricity in 2035 than it did in 2010.[28] Depending on how new and existing electricity demand is met in the future, electric sector water use could increase or decrease because of significant differences in the water use of electricity generating technologies and cooling systems.[12] Changes in electric sector water use influence its vulnerability to climate change, as well as the availability of water for use in other sectors across the economy. In light of the threat to U.S. electric power reliability, it will be critical to understand how future energy policies could impact electric sector water use.

This study explores how energy policies aimed at mitigating climate change through greenhouse gas emissions reductions could impact electric sector water use at a regional level. Specifically, we evaluate how four scenarios of U.S. energy sector carbon dioxide (CO_2) emission reductions could impact the water use of the electric power sector through 2055 using simulations of the EPA's U.S. 9-region (EPAUS9r) MARKAL (MARKet ALlocation) energy systems model.[19,11] Previous analysis has explored the effects on water use of CO_2 emissions reduction in the electric sector alone using the ReEDS model.[13] The advantage of the MARKAL model is its ability to capture economic interactions between multiple sectors of the energy system. In this analysis, MARKAL provides a cross-sector framework to evaluate how *system-wide* energy policies could impact electric sector water use.

II. Background

Thermoelectric power plants generate electricity by using steam to drive turbines. These plants require cooling systems to condense turbine exhaust steam back into boiler feed water. To meet this need, power plants divert water from nearby water bodies such as rivers and lakes. Cooling water is then pumped through a heat exchanger to condense the exhaust steam. Once cooling water has passed the heat exchanger, it is either discharged back into the environment, or pumped through a cooling system (such as towers and ponds) and recycled back into the condenser.

Water use is defined in terms of two parameters: withdrawal and consumption. Water withdrawal at a thermoelectric power plant is the total amount of water diverted from the environment. Water consumption is the amount of water lost as a result of the cooling process primarily as a result of evaporation. Over 99% of cooling water is withdrawn from surface water bodies, but some power plants also withdraw cooling water from groundwater sources.[29] In addition to freshwater, saline and brackish water is used to meet some thermoelectric cooling needs in coastal areas.

The most significant determinant of a thermoelectric power plant's water use is its cooling system. Thermoelectric cooling systems are divided into five classes: once-through, recirculating, pond, dry and hybrid. Once-through (or open-loop) cooling systems continuously withdraw water into the cooling system and discharge heated water back into the environment. Recirculating (or closed-loop) cooling systems use natural draft, forced draft or induced draft cooling towers to dissipate waste heat through evaporation and return the remaining water for further cooling use. As a result of this evaporative cooling process, recirculating cooling systems consume on average twice as much water as once-through cooling systems. However, recirculating cooling systems withdraw water only to replace the losses from the cooling water reservoir and therefore withdraw 10 to 100 times less water than a once-through cooling system.[12]

Pond cooling systems discharge heated cooling water into dedicated, open-air cooling water reservoirs and return cooler water from the same pond back into the cooling system. Dry cooling systems force air through the heat exchanger in place of water, thus eliminating the water needs of the power plant cooling system. However, the high cost and large parasitic power load required by these systems make them non-viable for the majority of large-scale power plants. Finally, hybrid cooling systems use a combination of water and air to meet cooling needs.

Roughly 31% of current national thermoelectric generating capacity uses once-through cooling systems while over 68% use recirculating and pond-cooling systems.[23] Hybrid and dry cooling comprise less than 1% of total installed cooling capacity.[2] The vast majority of new plants being built today employ recirculating cooling systems.[23] There are also several power generation technologies that are not thermoelectric systems. These include wind, solar photovoltaic and hydropower.

Thermoelectric water withdrawal and consumption factors are also heavily influenced by fuel type.[12] The vast majority of thermoelectric power plants are fueled by coal, natural gas or uranium, but slightly over one percent use renewable energy sources such as biomass, geothermal steam, or concentrated solar thermal.[25] Each of these fuel-types has unique cooling demands, causing substantial variability in the water use per unit electricity. For example, an average conventional nuclear power plant both withdraws and consumes almost twice as much water per MWh electricity output as a conventional coal plant.[12]

Power generation and emissions control technologies such as natural gas combined cycle, coal or biomass integrated-gasification combined cycle and carbon capture and storage technologies can also significantly alter the water use of a power plant. For instance, a combined cycle natural gas generating facility withdraws and consumes less than a third of the water that a conventional natural gas facility with the same type cooling system would per unit of electricity output. In coal-fired power plants, the addition of carbon-capture and storage technology could cause total water consumption to double and water withdrawal to triple as a result of the substantial increase in parasitic load on the plant and the increased need for water in the CO_2 removal process.

III. Methods

MARKAL Model

MARKAL is a least-cost optimization model that uses linear programming techniques to determine the optimal fuel-use and technology penetrations to achieve the lowest system-wide net present value energy system cost while meeting the demands and constraints defined for the system. Inputs of demands, costs, existing capacities, and constraints are defined in the EPAUS9r database. Model outputs are solved assuming perfect foresight over a modeling horizon from 2005 to 2055 with 5-year time steps. MARKAL model results are scenarios, and are in no way intended to represent predictions of the future. Instead, MARKAL results are "prescriptive" in that they represent an optimal outcome for the system as a whole, given costs, demands, and constraints.

MARKAL represents the entire U.S. energy system from primary energy supplies, through processing and conversion of those supplies into commodities, to the consumption of those commodities to meet end-use demands in the residential, commercial, industrial, and transportation sectors. The database represents air pollutant and greenhouse gas emissions for each phase in the energy system. The representation of primary energy supply accounts for both domestic and imported energy resources including fossil fuels, uranium, and renewable energy. Supply curves for each resource are accounted for in the model.[19] Processing and conversion technologies transform these raw resources into end-use commodities, such as electricity and gasoline. These processes include resource extraction, enrichment, refining, and electricity generation.

End-use demand changes throughout the time horizon of the model in response to projections of population growth, land-use change and economic development.[19] End-use demand is expressed in terms of demand for energy services rather than for a specific commodity. For example, most demand in the transportation sector is expressed in billions of vehicle miles travelled rather than in gallons of gasoline or kilowatt-hours (kWh) of electricity. This representation has the advantage of endogenously incorporating some consumer price response into the model optimization process. For example, if the price of electricity increases, the model assumes rational consumers will invest in energy efficient technologies, or possibly switch electric heating and cooking to natural gas.

While this representation models the ability of consumers to reduce their use of energy commodities (such as gasoline and electricity) in response to price, it does not represent their ability to reduce their demand for energy services. For example, the model represents the consumer's ability to switch from a gasoline-powered car to an electric car in response to high gasoline prices, but not to travel fewer miles. In this regard, MARKAL may fail to capture the full elasticity of demand to the price of end-use energy commodities. Moreover, because MARKAL is a system-wide optimization model, the fuel and technology choices may not necessarily reflect an optimal solution from the standpoint of the individual consumer.

The MARKAL model can also be used to explore energy system interactions between different U.S. regions. The EPAUS9r database divides the U.S into nine regions based on the

U.S. Census Divisions.[18] Each region is modeled as an independent energy system with different regional costs, resource availability, existing capacity, and end-use demands. Regions are connected through a trade network that allows transmission of electricity and transport of fuels. Electricity transmission is constrained to reflect the existing capacity of each regional connection. The model may increase the capacity of any existing connection at cost, but it may not create new connections between regions that are unconnected at the start of the model. Losses resulting from long-distance electricity transmission and costs associated with fuel transport are accounted for in the model. A separate import/export supply region is also modeled to represent the source of imported fuels, goods and electricity as well as the demand for exports outside the U.S.

Model Scenarios

This analysis models four energy policy scenarios to 2055: a baseline scenario (*Base*) and three alternative energy system-wide CO_2 emission reduction scenarios (*10% CO_2 Reduction*, *25% CO_2 Reduction*, and *50% CO_2 Reduction*). In the *Base* scenario, U.S. energy policy continues along a "business-as-usual" or reference trajectory in which no limits on CO_2 emissions are implemented. Data for *Base* scneario is taken from the from the Department of Energy's Annual Energy Outlook 2012 reference case (AEO 2012),[28,19] which documents historical demand, costs and existing capacity from 2005 to 2010 and projects these variables to 2035 in the same nine U.S. regions modeled in MARKAL.[28] Changes in variables after 2035 are projected based on extrapolation of the rate of change recorded in AEO 2012 between 2030 and 2035.[19] *Base* scenario output is calibrated against AEO 2012 for accuracy.

The *10%*, *25%*, and *50% CO_2 Reduction* scenarios represent three increasingly aggressive scenarios of U.S. energy system-wide CO_2 emission constraints. These scenarios differ from the base case only in that they include constraints on emissions of CO_2. Constraints were calculated as percent reductions from year 2005 *Base* scenario model results. Constraints first take effect in 2015 and decrease linearly in each time step thereafter until they achieve target reductions in 2055 that are 10, 25 and 50 percent lower than the *Base* scenario 2005 CO_2 emissions respectively.

For comparison, the American Clean Energy and Security Act of 2009 (H.R. 2454) would have required total U.S. CO_2 emissions be reduced to 83% of 2005 values by 2050.[10] An additional point of reference is President Obama's 2009 proposed target of reducing CO_2 emissions 17% by 2020 in advance of the 2009 Copenhagen Climate Summit.[14] These scenarios were then compared against the *Base* and analyzed for their effect on demand for electricity, electric sector technology mix, and associated water use.

All four scenarios model the implementation of numerous existing energy policies including renewable portfolio standards (RPS), the Clean Air Interstate Rule (CAIR), and Corporate Average Fuel Economy (CAFE). The existing renewable portfolio standards (RPS) are represented as binding constraints. These constraints were defined for each region based on aggregations of every state's individual RPS. Region 6 is the only region in which no state has yet approved any renewable portfolio standards. All state RPS regulations were determined using the U.S. Department of Energy's Database of State Incentives for Renewables and Efficiency (DSIRE).[16] CAIR is implemented in Eastern regions in the EPAUS9r database as constraints on total emissions of SO_2 and NO_x. Finally, CAFE standards are also represented as constraints on new vehicles in each region in the transportation sector, forcing increases in vehicle fuel economy.

Water Use in Electricity Generation

Previous analysis of energy system water use with the MARKAL model focused on water consumption and used a simplified representation of the diversity of cooling system technologies.[4] In this study, the EPAUS9r database was restructured to improve the representation of water withdrawal and consumption by different types of electricity-generating technologies, and to identify the types of cooling technologies used by individual existing facilities. Water use data for electricity generating technologies was taken from a 2011 technical report by the National Renewable Energy Laboratory (NREL).[12] This dataset provides estimates of the water withdrawal and consumption of electricity generating systems for all fuel types, technologies and cooling systems modeled in the EPAUS9R database.

Water factors from the NREL study were converted into units of millions of gallons consumed and withdrawn per petajoule (PJ) of electricity output for each electricity-generating technology. These water factors are displayed in Figure 1 for technologies operating recirculating, hybrid and once-through cooling systems. In general, water factors decrease for plants with greater generation efficiency. Based on analysis by the U.S. Department of Energy, it was assumed that all electric generating plants built in the future will install recirculating cooling systems.[23]

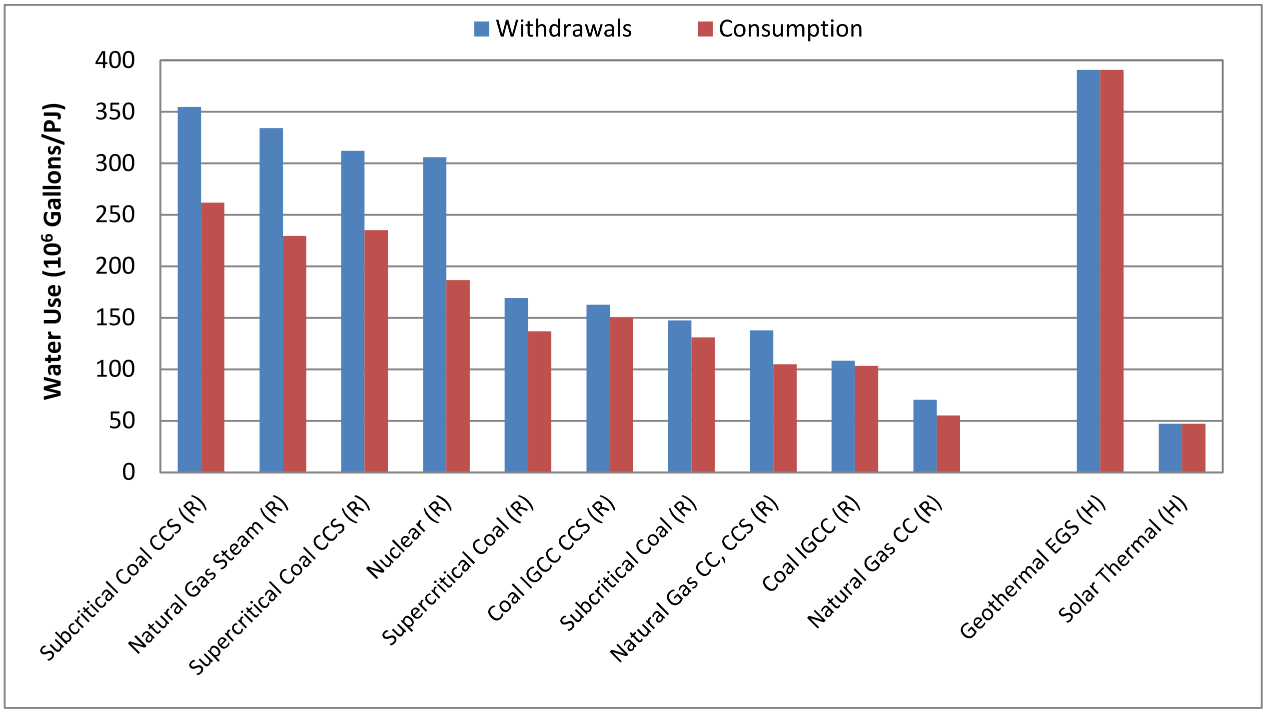
It was also assumed that wind turbines neither withdraw nor consume any water, based on NREL estimates.[12] Some analyses attribute large water consumption factors to hydropower based on increased evaporation from reservoirs.[20,7] However, we defined no water withdrawal or consumption for hydroelectric power generation because the evaporative losses resulting from hydropower reservoirs can also be attributed to other purposes such as water supply, flood control and recreation. This study only analyzes the quantity of water used during the process of electricity generation. As such, water used by other sectors and processes such as resource extraction are not reported here. Effects on water quality are also not addressed in this study.

To determine the total once-through and recirculating cooling capacities currently installed on existing thermoelectric power plants, we aggregated power plant survey data from the DOE's Energy Information Administration (EIA). We compiled cooling system data from 2005 EIA Form 767 as well as 2006-2011 EIA Form 860 reports.[26,27] In some cases, cooling system entries differed between years for the same unit. Wherever cooling system entries from two survey years conflicted, the later entry was used. These survey datasets provided cooling system codes for the units on many existing natural gas and coal-fired thermoelectric power plants. However, these forms do not collect data on nuclear power plants. In addition, many of the power plants surveyed omitted the cooling system entry on the survey response. This resulted in significant gaps in the aggregated dataset including no cooling data on 128 of 600 coal plants, 558 of 5,094 natural gas plants and all 104 nuclear power plants.

To complete this dataset, power plants with cooling systems unaccounted for in EIA datasets were individually identified and coded by visual identification with satellite imagery. Nuclear power plants were located with the Nuclear Regulatory Commission's

Facility Locator.[16] Latitude and longitude data for coal-fired power plants and some natural gas facilities were identified with the Center for Media and Democracy's *Sourcewatch*[3]. Using location data, satellite images of each power plant were examined with *Bing* and *Google* maps and compared to known photographs of the plant. Through identification of definitive cooling systems features such as cooling towers and ponds, each plant cooling system was coded. 131 natural gas power plants could not be located and were assumed to use recirculating cooling systems because they are by far the most prevalent.

1A.



1B.

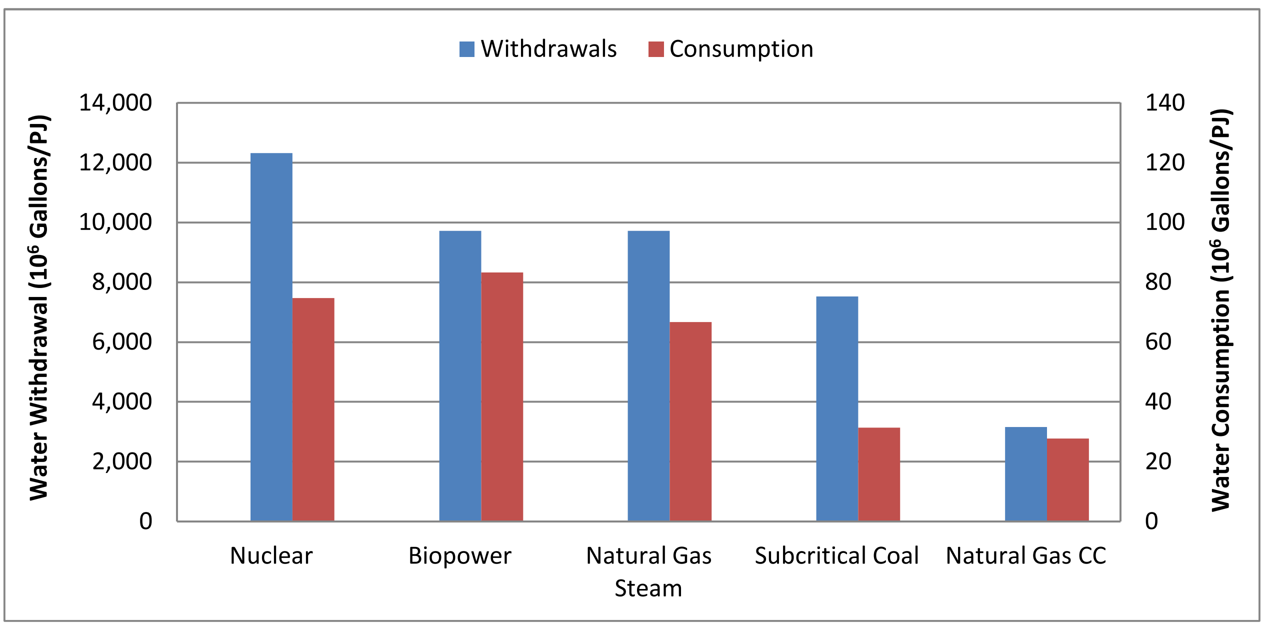


Figure 1. Water Withdrawal and Consumption Factors. Water withdrawal and consumption factors for all modeled technologies using recirculating (R) and hybrid (H) cooling systems (1A) and for once-through cooling (1B). Technology acronyms: CC = combined cycle, IGCC = integrated gasification combined cycle, CCS = carbon capture and storage, EGS = enhanced geothermal system.

IV. Results

We first present changes in the total energy system response to CO_2 constraints, then changes within the electric sector, and finally implications of those changes for electric sector water withdrawal and consumption.

Model Response to Constraints by Sector

Total U.S. energy system CO_2 emissions and electric sector CO_2 emissions from 2005 to 2055 for all four policy scenarios are shown in Figures 2A and 2B respectively. Model results under all scenarios show an initial decrease in both total system and electric sector CO_2 emissions between 2005 and 2015 in response to a drop in energy demand during that period due to economic conditions.[28] In the *Base* scenario, total system and electric sector CO_2 emissions gradually increase from 2015 through the model time horizon as demand for energy services continues to increase. By 2055, total system CO_2 emissions exceed 2005 values by 10%. CO_2 emissions from the electric sector in 2055 remain slightly below 2005 values in spite of increased demand as a result of increased electric generating efficiency.

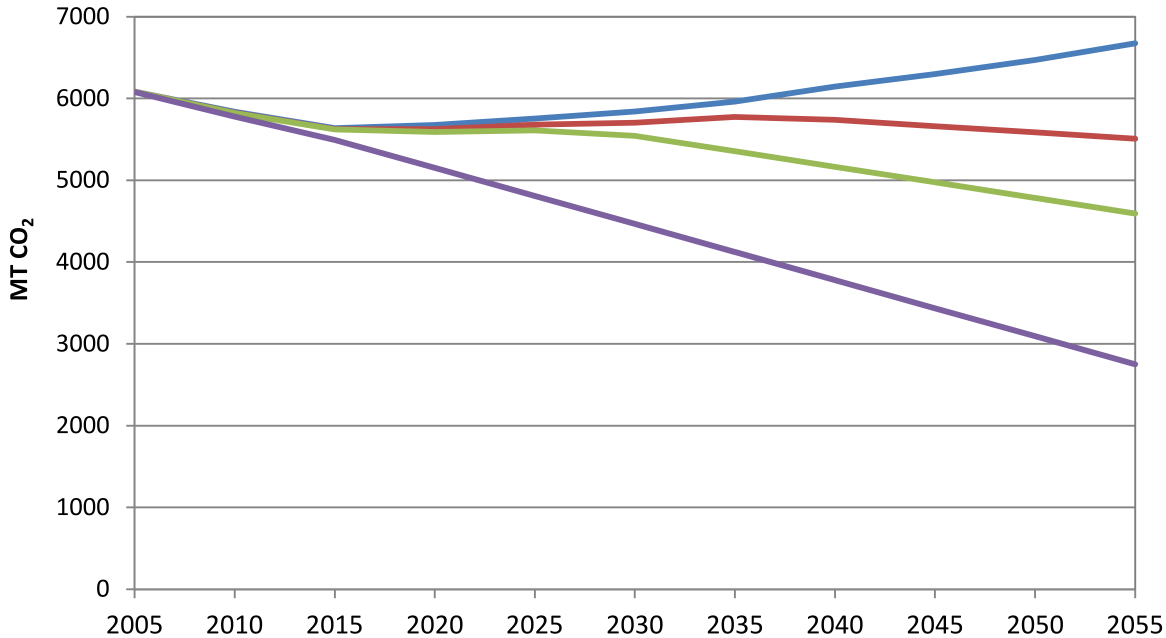
In both the *10%* and *25% CO_2 Reduction* scenarios, electric sector emissions actually decrease more than total energy system CO_2 emissions over the model horizon because other sectors (such as transportation) continue to grow in CO_2 emissions during that time. This discrepancy between the CO_2 emissions reduction shares of different sectors illustrates that it is substantially cheaper to reduce CO_2 emissions in the electric sector than in other sectors. As a result, the model maximizes electric sector emissions reductions before it becomes economically viable to make changes in other sectors.

Under the *50% CO_2 Reduction* scenario, electric sector CO_2 emissions drop to nearly zero by 2055. Total energy system CO_2 emissions decrease by 3,327 Mt/yr in 2055. Of these reductions, only 60% comes from the electric sector (1,996 Mt) and 30% comes from the transportation sector (998 Mt). The remaining decreases come from the industrial, residential and commercial sectors. CO_2 emissions by sector from 2005 to 2055 under the *50% CO_2 Reduction* scenario are shown in Figure 3A.

Changes in transportation sector emissions first take on a significant share of total system emissions reductions in 2045, once electric sector emissions have already decreased to nearly 10% of their 2005 value. Transportation sector emissions reductions are achieved primarily through changes in light duty vehicles. Differences in light duty vehicle technology use between the base and the *50% CO_2 Reduction* scenarios are shown in Figure 3B. Emission reductions by the light duty vehicle sector are achieved through increased use of ethanol (E85) in vehicles operating internal combustion engines as well as plug-in hybrids. Electric vehicles and vehicles running on compressed natural gas also play a role in reducing light duty vehicle emissions.

The substantial increase in the use of both electric vehicles and plug-in hybrids after 2045 under the *50% CO_2 Reduction* scenario means that the total demand for electricity by the light duty vehicle sector increases dramatically. This increased use of electricity by the transportation sector requires a corresponding increase in total electricity production in the *50% CO_2 Reduction* scenario beginning in 2045 (Figure 4).

2A.



2B.

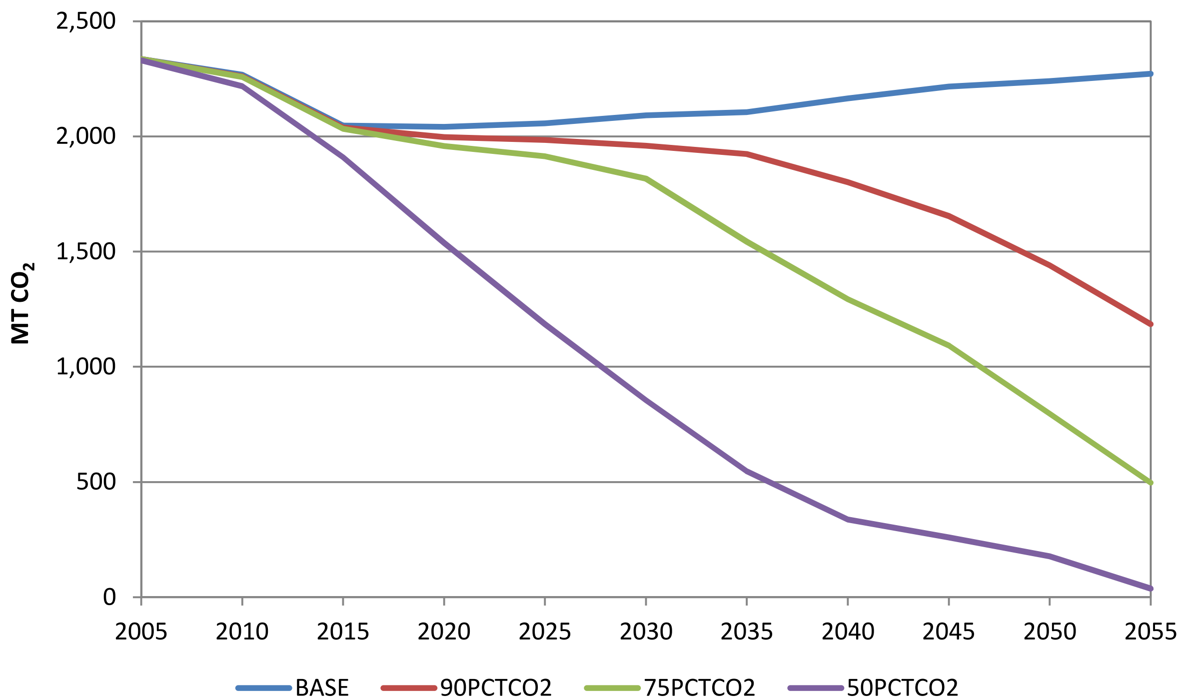
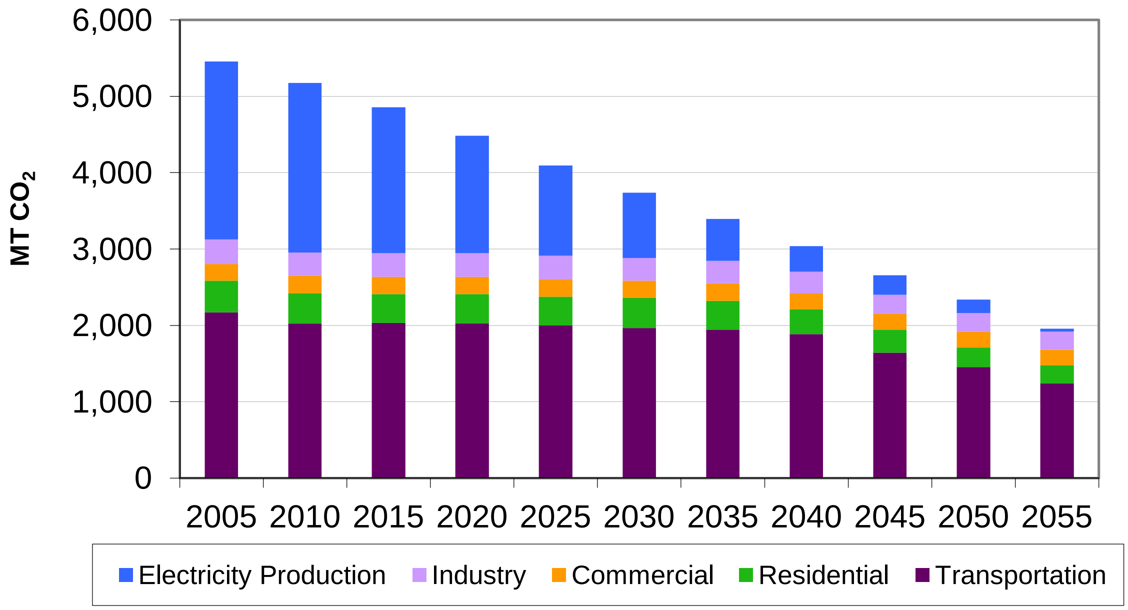


Figure 2. System and Sector CO_2 Emissions. U.S energy system CO_2 emissions for all scenarios (2A). Electric sector CO_2 emissions for all scenarios (2B).

3A.



3B.

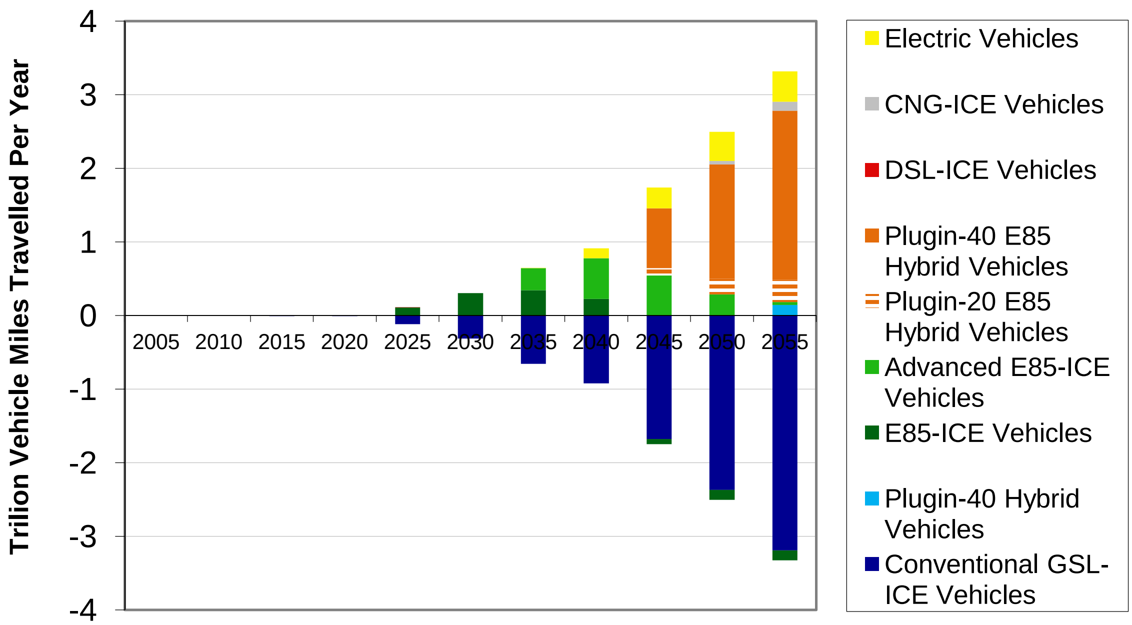


Figure 3. CO_2 Emissions by Sector and Light Duty Vehicle Technologies. CO_2 emissions from end-use sectors in the *50% CO_2 Reduction* scenario (3A). Differences in light duty vehicle technologies between the *Base* and *50% CO_2 Reduction* scenarios (3B). Positive values indicate technologies used more in the *50% CO_2 Reduction* scenario and negative values indicate technologies used more in the *Base* scenario. Figure legend abbreviations: CNG = compressed natural gas, ICE = internal combustion engine, E85 = 85% ethanol fuel blend, GSL = gasoline. Plug-in X, where X refers to the vehicles electric range in miles.

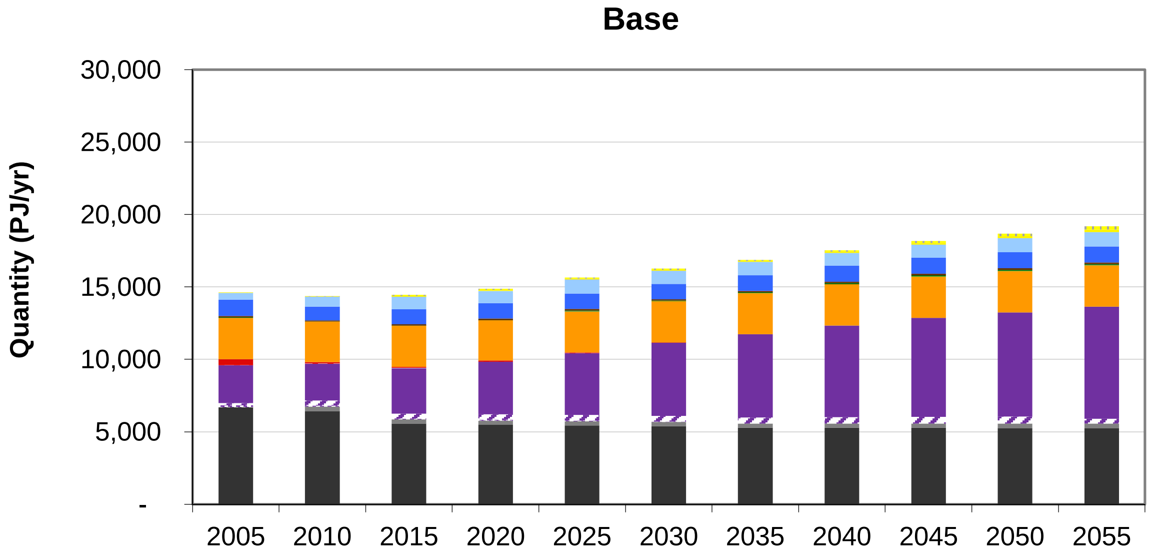
Electric Sector Technology Changes

Electric sector technology use in each modeled scenario is shown in Figure 4. Under the *10% CO_2 Reduction* scenario (Figure 4B), most conventional coal-fired power plants that remained active to 2055 under the base scenario are gradually taken out of use. The majority of the conventional coal facilities that are not retired are retrofitted with carbon capture and storage (CCS) technology. In place of the coal facilities that were taken offline, the model significantly increases power generation by natural gas combined cycle power plants and wind power.

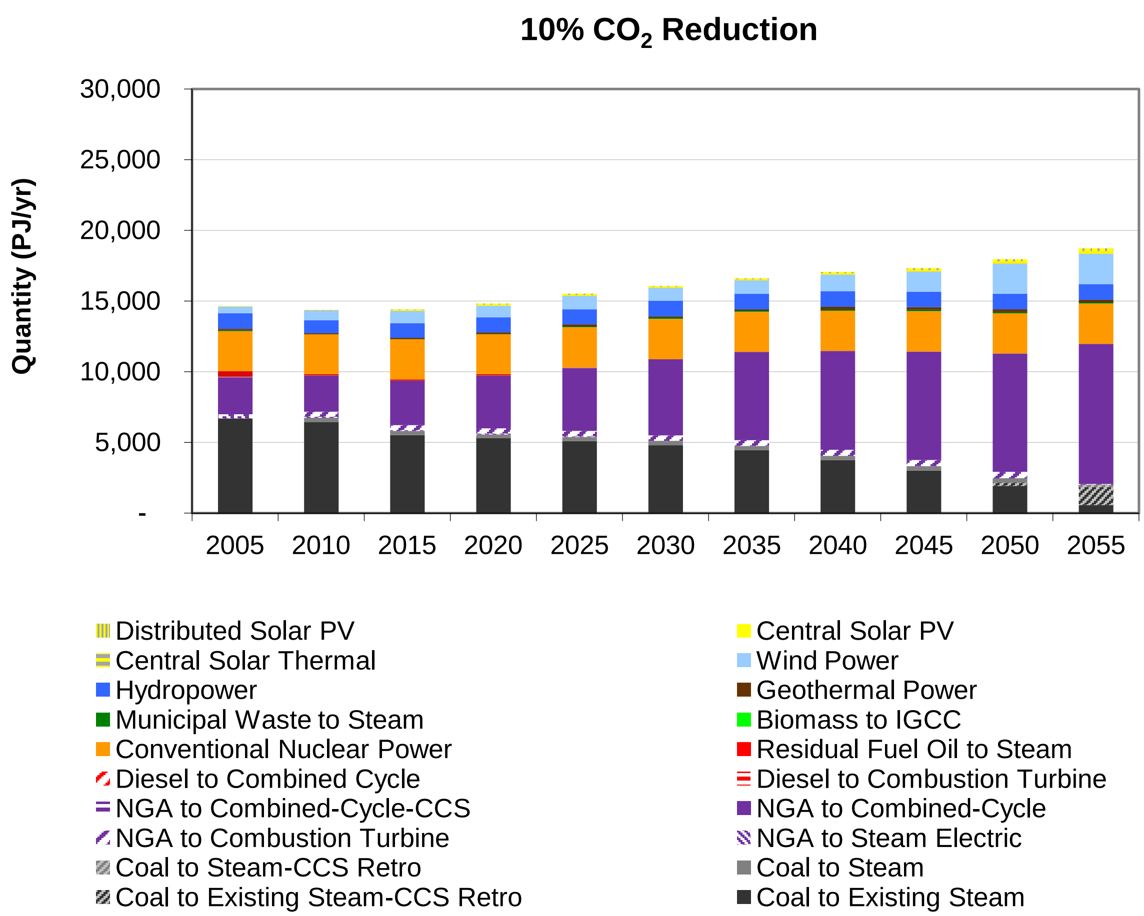
In the 2*5% CO_2 Reduction* scenario, conventional coal plants are retired more rapidly and are taken completely out of use by 2050. The model continues to rely primarily on natural gas combined cycle and wind to replace these decreases in coal use. In 2040, solar thermal power production is also implemented to contribute a significant share of total electricity generation, and its use increases throughout the remaining years. In 2055, natural gas combined cycle with CCS replaces over 30% of existing natural gas power generation.

In the *50% CO_2 Reduction* scenario, the significant increase in electricity demand from light duty vehicle electrification leads to large increases in total electricity generation after 2035 (33% greater in 2055 than in the base case). At the same time, total electric sector CO_2 emissions approach zero (Figure 1B). To simultaneously increase electricity generation and decrease emissions by such substantial margins requires great changes in electric sector technology mix. Conventional coal-fired power plants are taken completely out of use by 2035. In the same year, natural gas combined cycle with CCS begins to replace existing natural gas and grows to generate 8513 PJ by 2055. Total U.S. carbon storage capacity is represented in the model, but does not impact the CCS use because the storage capacity is so great.[15] Use of renewable power, including wind, solar, and hydropower, also grow to contribute over 40% of total electricity generation.

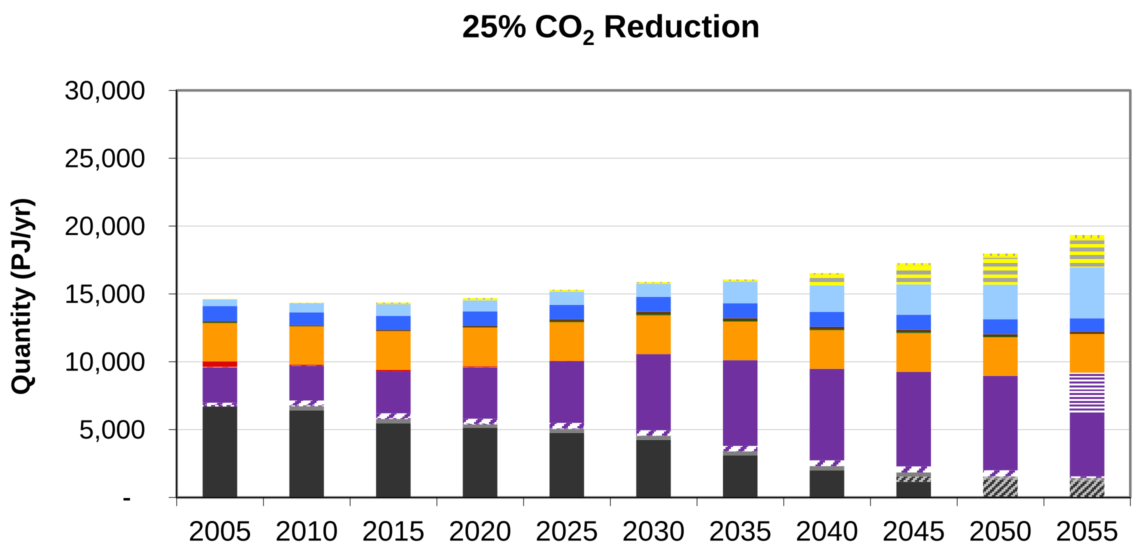
4A.


Base
Quantity (PJ/yr)
30,000
25,000
20,000
15,000
10,000
5,000
-
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
2055

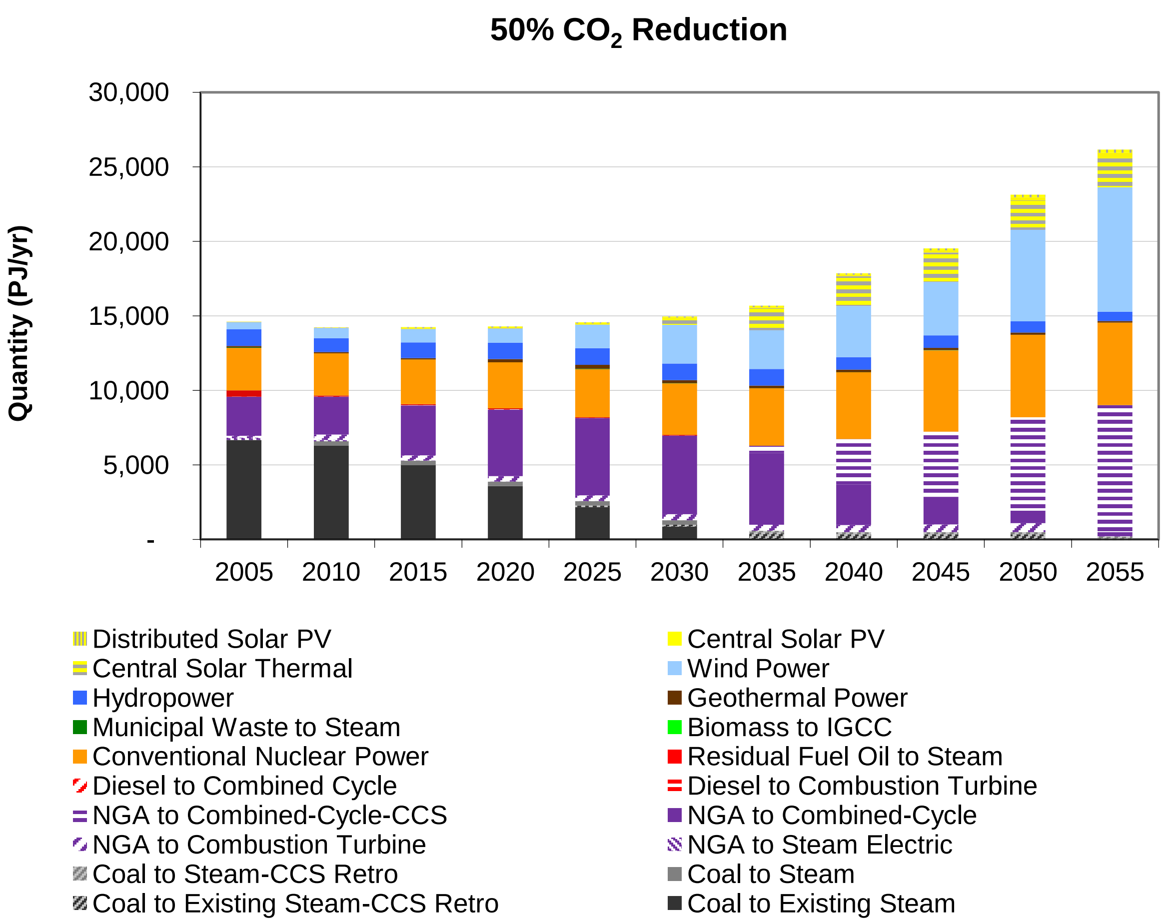
4B.


10% CO_2 Reduction
Quantity (PJ/yr)
30,000
25,000
20,000
15,000
10,000
5,000
-
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
2055
Distributed Solar PV
Central Solar PV
Central Solar Thermal
Wind Power
Hydropower
Geothermal Power
Municipal Waste to Steam
Biomass to IGCC
Conventional Nuclear Power
Residual Fuel Oil to Steam
Diesel to Combined Cycle
Diesel to Combustion Turbine
NGA to Combined-Cycle-CCS
NGA to Combined-Cycle
NGA to Combustion Turbine
NGA to Steam Electric
Coal to Steam-CCS Retro
Coal to Steam
Coal to Existing Steam-CCS Retro
Coal to Existing Steam

4C.



4D.



Figures 4. Electric Sector Technology Mix. Electricity production by technology for each scenario from 2005 to 2055.

Electric Sector Technology Changes by Region

The electric sector technology mix for each region under the *Base* and *50% CO_2 Reduction* scenarios for 2055 is shown in Figure 5. The electric sector response to CO_2 emissions constraints varies considerably between regions. In eastern regions (1, 2, 3, 5, and 6), use of nuclear power and natural gas combined cycle with CCS increases dramatically by 2055 under the *50% CO_2 Reduction* scenario. In contrast, central and western regions (4, 7 and 8) expand electricity-generating capacity primarily with wind power. Regions 9 and 7 also incorporate significant generating capacity from concentrated solar thermal as well as natural gas combined cycle with CCS.

One of the primary drivers for these differences in technology choices between regions is resource availability. In eastern regions, renewable resource availability (such as for wind, solar or geothermal power generation) is relatively poor.[6,24,28] Technology choices in eastern regions are therefore restricted to rely primarily on non-renewable low-carbon technologies, such as nuclear and natural gas with CCS, to satisfy CO_2 constraints. In contrast, western regions have favorable renewable resource availability, making the implementation of wind and solar power far more attractive in those regions.[6,24,28]

Another significant determinant of the electricity generation technology differences between regions is the projected vehicle-miles-traveled (VMT) in each region. Region 5 is projected to see the greatest expansion in total VMT's of any region over the modeled time horizon. This has several effects on the model results. First, as a result of these increases, region 5 shows the largest increase in total electricity production from the base to the *50% CO_2 Reduction* scenario of any region. Increased VMTs are also a driver for the substantial implementation of nuclear power in region 5 under the *50% CO_2 Reduction* scenario. Electric vehicles and plug-in hybrids are typically charged at night and thus have the effect of increasing base load demand and decreasing fluctuations in demand for electricity. This increase in base load electricity demand makes nuclear power production in that region more favorable.

In contrast, lower projected growth in population and VMT in mountain western regions mean that implementation of renewable energy technologies (particularly wind) can be used to supplement electricity in other regions when it is available. Total interregional transfers increase by almost 40% from the Base to the 50% CO_2 Reduction Scenario (Figure 6). Under the *50% CO_2 Reduction* scenario, regions 4, 7, and 8 use their substantial renewable energy resources to supply low carbon electricity to other regions through trading. These regions export 28%, 9% and 17% of their total electricity production respectively in 2055. To accommodate these substantial exports, regions 4 and 8 undergo the largest increase in total electricity generation by percentage of any region, as they increase by 75% and 98% in total electricity generation respectively.

All other regions become net importers, with the most substantial imports going to regions 5 and 6. Though region 5 remains one of the largest importers nationally, its share of total electricity imports decreases from the Base to the *50% CO_2 Reduction* scenario because of its substantial increase in nuclear base load capacity. All regions except for region 6 also increase total electricity generation from the *Base* to the *50% CO_2 Reduction* scenario in 2055 to accommodate the increased demand for electricity from electric and plug-in vehicles. Imports account for 41% of all electricity used in region 6. This heavy reliance on imported electricity in region 6 is likely the product of low renewable energy availability in that region paired with immediate proximity to regions with vastly greater renewable energy potential (regions 4 and 7), making it particularly cost-effective to import electricity generation in that region.

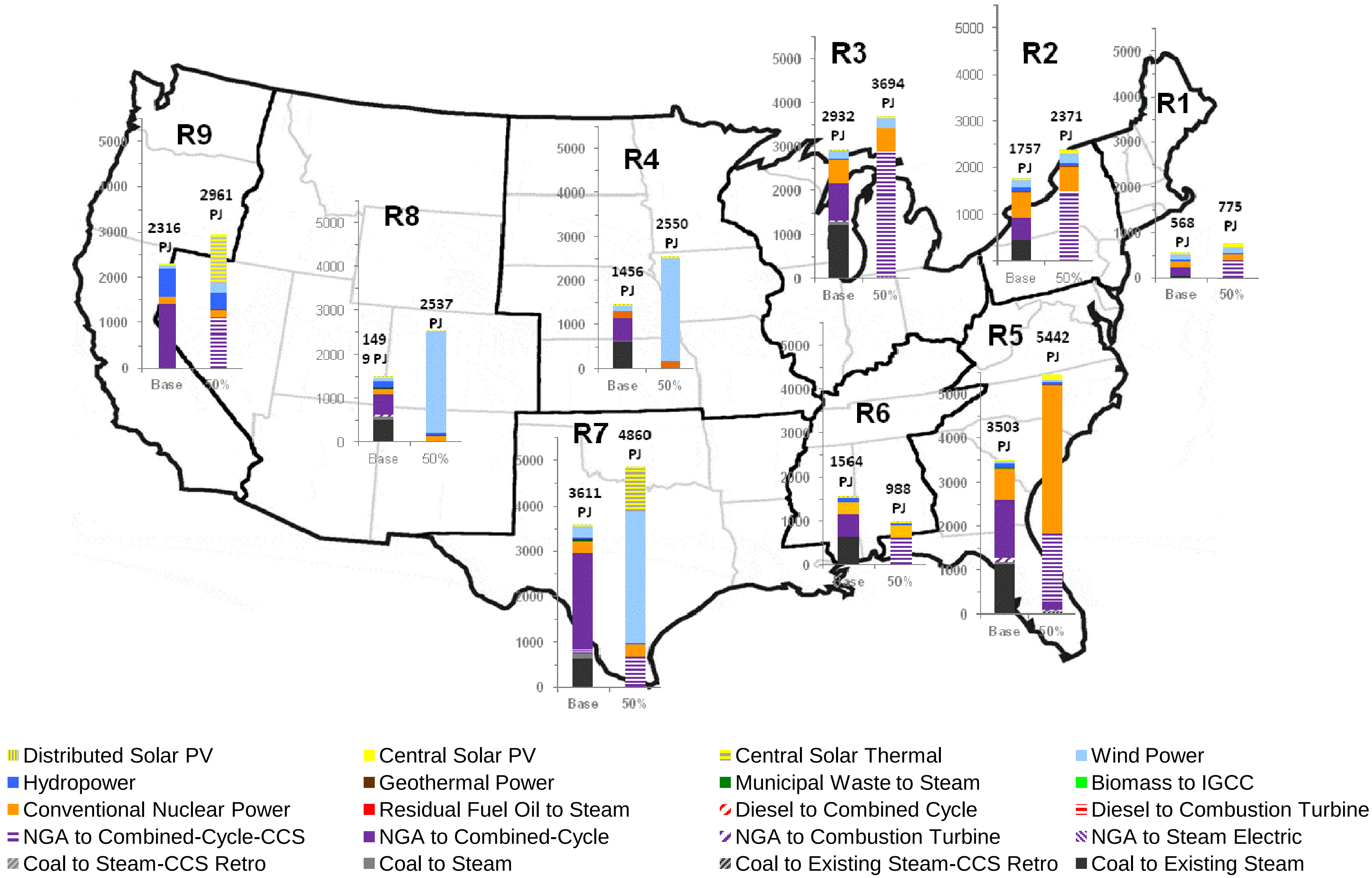
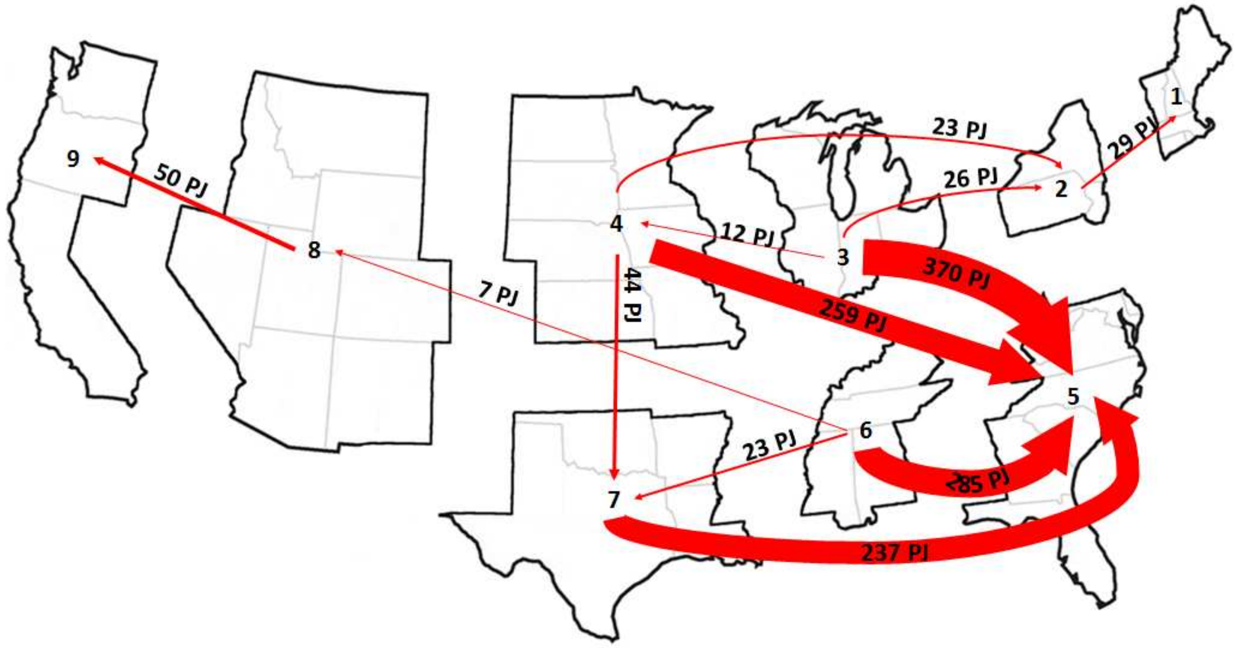
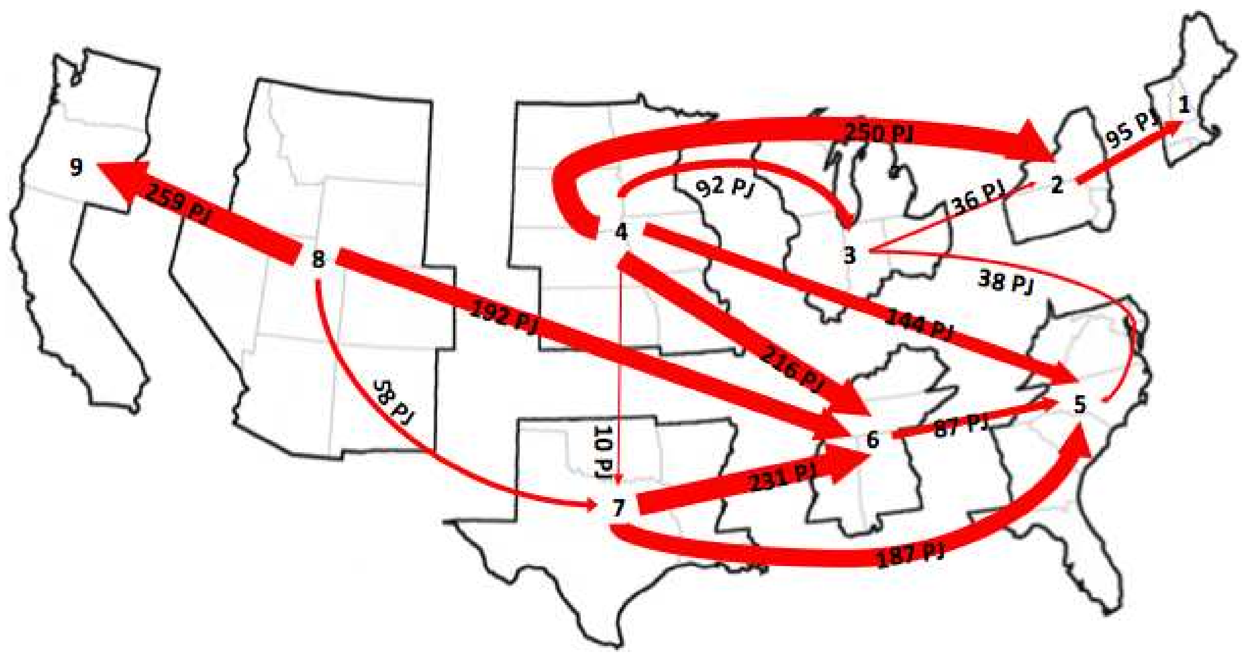


Figure 5. Electric Sector Technology Mix by Region. Electricity production (PJ) by technology in the *Base* (left bar) and the *50% CO_2 Reduction* scenarios (right bar) in 2055 in nine regions.

6A.



6B.



Figures 6. Net Flows of Electricity. Net flows of electricity between regions under the Base scenario (6A) and 50% CO_2 emissions reduction scenario (6B) in 2055. Arrow width is proportional to the quantity of electricity traded.

Electric Sector Water Use

Total electric sector water withdrawal and consumption for all four scenarios are shown in Figure 7. This figure shows that electric sector water withdrawal is strongly influenced by CO_2 constraints; as CO_2 emissions decrease, water withdrawal decreases as well. In the *50% CO_2 Reduction* scenario, total electric sector water withdrawal decreases to less than 45% of 2005 values by 2035. This considerable reduction in water withdrawal results from several factors. First, as existing once-through capacity is replaced with newer technologies, our assumption that all new power plants will be built with recirculating cooling systems causes water withdrawal to decrease substantially. Second, a large share of total electricity generation is shifted to lower-water use renewable power sources (wind and solar). Finally, replacement of old power generating facilities with newer technologies mean total electric generating efficiency increases over the model horizon, thereby decreasing water withdrawal.

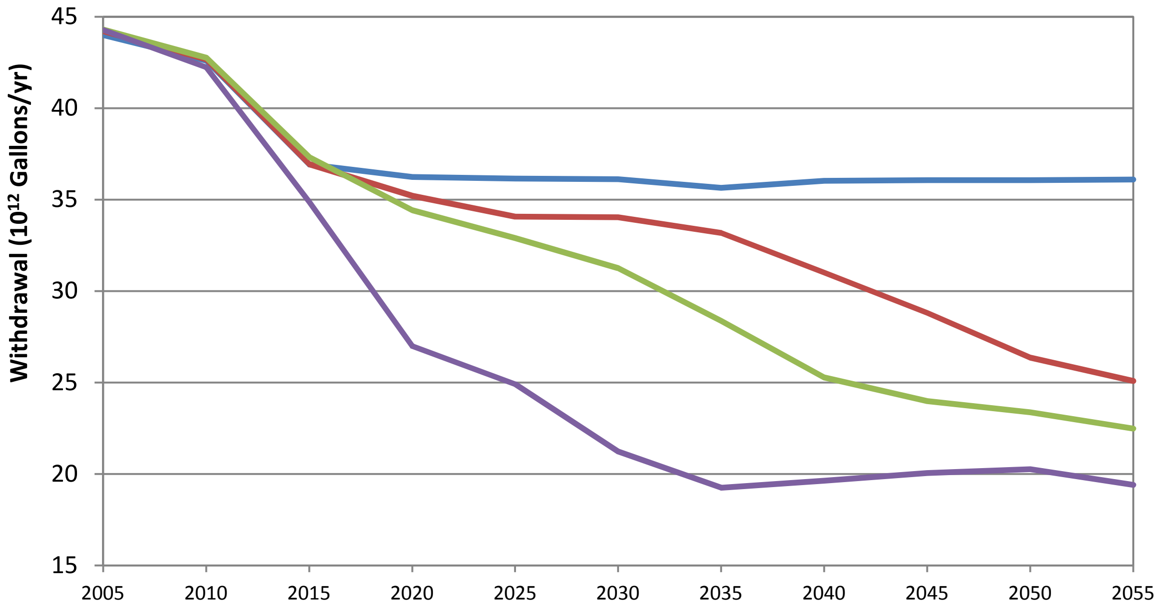
The response of electric sector water consumption is more complex. Under the *Base* scenario, water consumption increases over the model time horizon as a result of increased electricity production and because existing power plants with once-through cooling systems are gradually replaced by plants with recirculating cooling systems, for which water withdrawal is less but consumption is greater. Under all three CO_2 constraint scenarios, there is a period in which total electric sector water consumption decreases as the CO_2 emissions constraints force the model to retire conventional coal-fired power plants and replace them with more efficient natural gas combined cycle plants. These decreases occur at different times in different scenarios, coinciding with the rate of conventional coal plant retirement. For the *10%*, *25%*, and *50% CO_2 Reduction* scenarios, the lowest consumption occurs in 2050, 2040, and 2030 respectively.

After this initial decrease, water consumption in each scenario then begins to increase again as new coal and natural gas CCS plants are brought online. CCS technology consumes large quantities of water because of the considerable parasitic load it imposes on its generator and because the amine scrubbing process modeled here is highly water intensive.[12] Under the *50% CO_2 Reduction* scenario, water consumption increases by over 60% from 2005 values by 2055. This considerable jump in water consumption is largely a product of the increased use of natural gas combined cycle with CCS as well as the faster transition to recirculating cooling.

Each CO_2 emissions constraint scenario has a unique impact on total electric sector water consumption. In the 1*0% CO_2 Reduction* scenario, electric sector water consumption is less than base case consumption throughout the model horizon because of the substantial conventional coal plant retirement and small CCS penetration. In the 2*5% CO_2 Reduction* scenario, electric sector water consumption remains significantly below base case values until the last model time step when CCS implementation begins to take on a more substantial share of total electricity production. Finally, under the *50% CO_2 Reduction* scenario, water consumption increases 40% over base case values by 2055. This considerable jump in water consumption is largely a product of the considerable use of natural gas combined cycle with CCS as well as the faster transition to recirculating cooling.

Regional shares of total electric sector water withdrawal and consumption are shown for the *Base* and *50% CO_2 Reduction* scenarios in Figure 8. These shares remain relatively static throughout the time horizon in the base case. As CO_2 constraints take effect, regional shares of both total electric sector water withdrawal and consumption begin to change. In the *50% CO_2 Reduction* scenario, regions 4, 6, 7 and 8 show significant decreases in overall water withdrawal. This results from the decrease in total electricity output (region 6) and the considerable increase in wind-powered electricity generation in those regions (regions 4, 7 and 8). For the same scenario, regions 3 and 5 make significant increases in total electric sector water consumption. These changes reflect major increases in the use of nuclear power and natural gas with CCS electricity generating technologies as well as increased implementation of recirculating cooling systems.

7A.



7B.

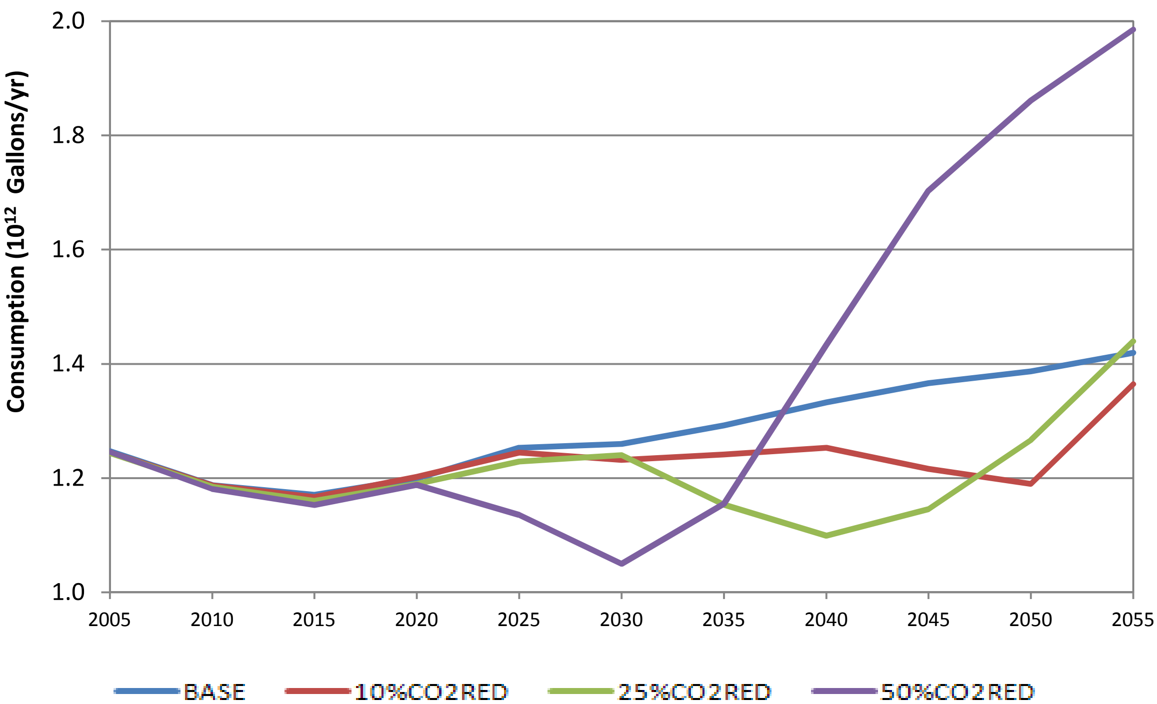


Figure 7. Electric Sector Water Use. Electric sector water withdrawal (7A) and consumption (7B).

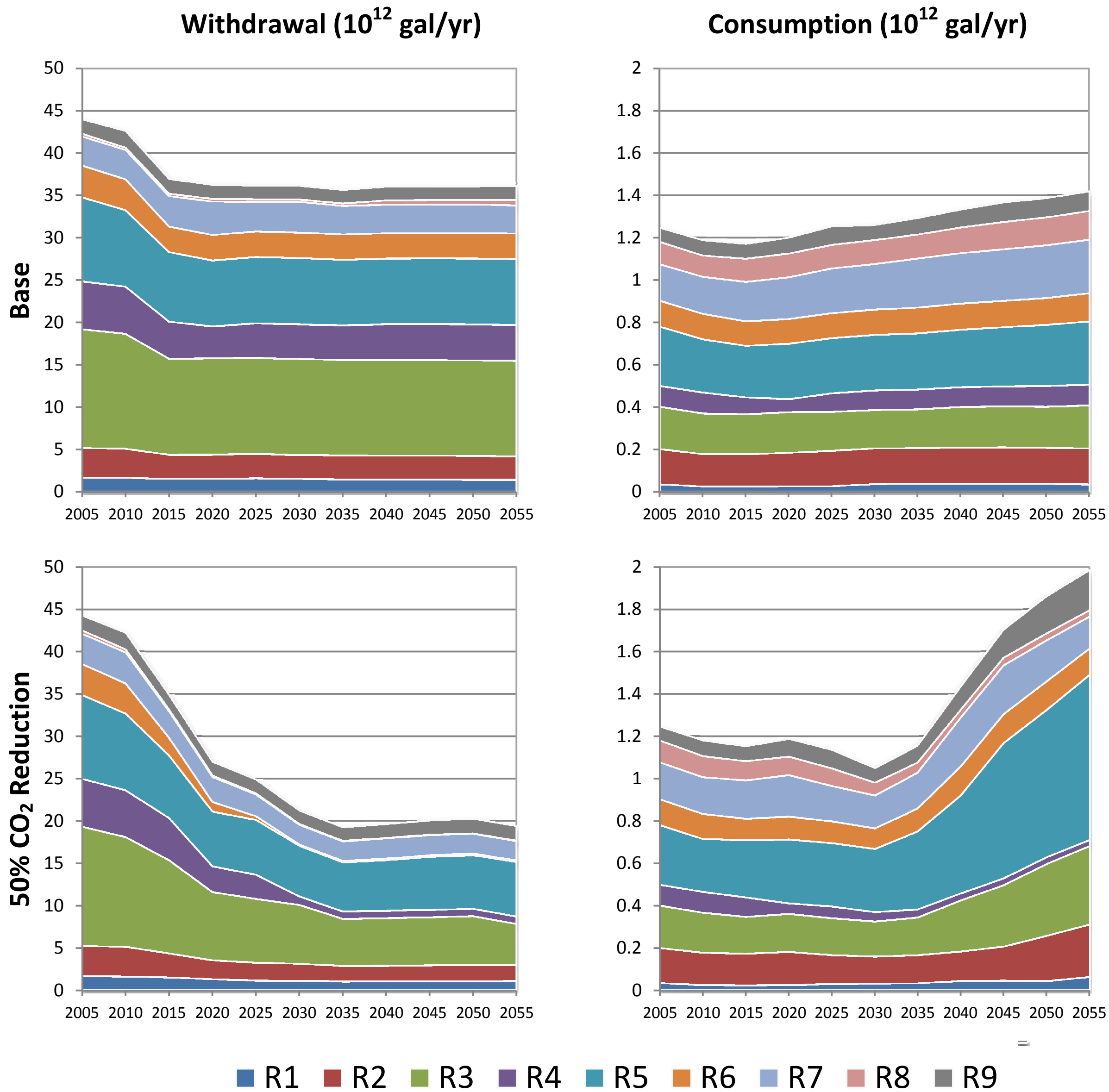


Figure 8. Electric sector water withdrawal and consumption by region for the *Base* and *50% CO_2 Reduction* scenarios.

V. Sensitivity Analysis

Three technologies dominated the electric sector under the *50% CO_2 Reduction* scenario: natural gas with CCS, nuclear, and wind. Here we test the sensitivity of the results of this scenario to incentives and restrictions on these three technologies. We focus our comparison on results in the end-year of the model: 2055.

Scenarios

We conducted nine sensitivity analysis scenarios. Each scenario incorporates a change to a single technology while maintaining the 50% CO_2 emissions reduction constraint. In the *CCS Cost Down* scenario, the investment costs for all CCS technologies were reduced 50% in each year of the model time horizon relative to their cost under the 50% CO_2 Reduction scenario. The *CCS Cost Up* scenario increases them 50%. The *No CCS* scenario restricts the model from using any CCS to meet electricity demand, either through retrofits or through construction of new plants.

In the *No Nuclear Constraint* scenario, constraints on nuclear power that exist under base case conditions were removed. These constraints are based on AEO 2012 projections, and do not impact system results in the *Base* scenario, but restrict total nuclear power under the *50% CO_2 Reduction* scenario. In the *Nuclear Cost Up* scenario, the investment cost for new nuclear power plants is increased 50% in all model years relative to the cost under the *50% CO_2 Reduction* scenario. The *No New Nuclear* scenario restricts the model from building any new nuclear capacity entirely.

The *Wind Cost Down* and *Wind Cost Up* scenarios reduced and increased respectively the investment cost for all wind technology by 50% relative to the costs under the *50% CO_2 Reduction* scenario in all modeled years. Finally, the *Reduced Wind* scenario restricts electricity generation from wind to half of that generated under the *50% CO_2 Reduction* scenario in year 2055 for regions 4, 7, and 8 throughout the model time horizon. Wind power in all other regions was not restricted in this scenario because wind did not serve as a primary source of electricity generation in those regions under the *50% CO_2 Reduction* scenario.

Results

Net changes in electricity generation from five major energy sources (coal, natural gas, solar, nuclear and wind) relative to the *50% CO_2 Reduction* scenario under each sensitivity analysis scenario are shown in Figure 9A. Net changes in total water withdrawal and consumption for each scenario are shown in Figure 9B. For comparison, total national electricity generation in 2055 under the *50% CO_2 Reduction* scenario was 26,136 PJ while national water withdrawal was 19.4 trillion gallons and water consumption was 1.9 trillion gallons.

The model responded to the *CCS Cost Down* scenario with increased use of natural gas CCS and coal CCS and decreased use of nuclear power and wind. Total electricity generation increased slightly in response to this decrease in cost. These changes led to a moderate reduction in overall water withdrawal and consumption in response to the decreased nuclear power (2% and 1% respectively relative to the 50% CO_2 Reduction scenario national total).

The *CCS Cost Up* scenario caused a 3221 PJ decrease in electricity generation from natural gas, but a 610 PJ increase in the use of CCS retrofits to existing coal capacity, even though the investment cost for those retrofits were also increased in that scenario. This occurred because the coal CCS retrofits were the cheapest CCS option available to the model. In place of the natural gas, the model used increased wind and solar. Overall, these changes resulted in an over 1100 PJ decrease in total electricity generation. Water withdrawal increased substantially (0.37 trillion gallons) as a result of the continued use of existing coal facilities with open loop cooling systems. Water consumption, however, decreased as the overall use of CCS technology was significantly reduced from the *50% CO_2 Reduction* scenario.

The *No CCS* scenario produced the most drastic changes in technology mix and total electricity generation. Total electricity generation decreased 3,881 PJ from the *50% CO_2 Reduction* scenario – nearly 15% with respect to the *50% CO_2 Reduction* scenario. This reduction in total electricity generation was accommodated by reductions in transportation sector electricity use. In response to the increased price of electricity, the model used fewer electric vehicles and, in their place, used more vehicles running on biofuels and compressed natural gas.

Changes in technology mix included an over 8000 PJ decrease in the use of natural gas and coal (nearly all of what was used under the *50% CO_2 Reduction* scenario), and an increase in the use of solar and wind of almost 4500 PJ (nearly a 50% increase). These changes led to a 1.74 trillion gallon decrease in electric sector water withdrawal (8.9% of the national total in the *50% CO_2 Reduction* scenario) and a 0.9 trillion gallon decrease in electric sector water consumption (45% of the national total in the *50% CO_2 Reduction* scenario).

In the *No Nuclear Constraint* scenario, 3022 PJ more nuclear power was used to meet electricity demand than had been used in the *50% CO_2 Reduction* scenario. This increase in nuclear power primarily replaced natural gas combined cycle with CCS and led to increases in both water withdrawal and consumption. Impact on coal, solar, wind and total electricity generation was negligible. The *Nuclear Cost Up* and the *No New Nuclear* scenario produced almost identical results. Nuclear electricity generation decreased 2670 PJ and was replaced by an 1811 PJ increase in the use of natural gas combined cycle with CCS. Both scenarios led to a small decrease in total electricity generation (254 PJ). Both scenarios produced moderate decreases in water withdrawal (0.45 trillion gallons, 2% of the national total in the *50% CO_2 Reduction* scenario) and consumption (0.28 trillion gallons, 14% of the national total in the *50% CO_2 Reduction* scenario).

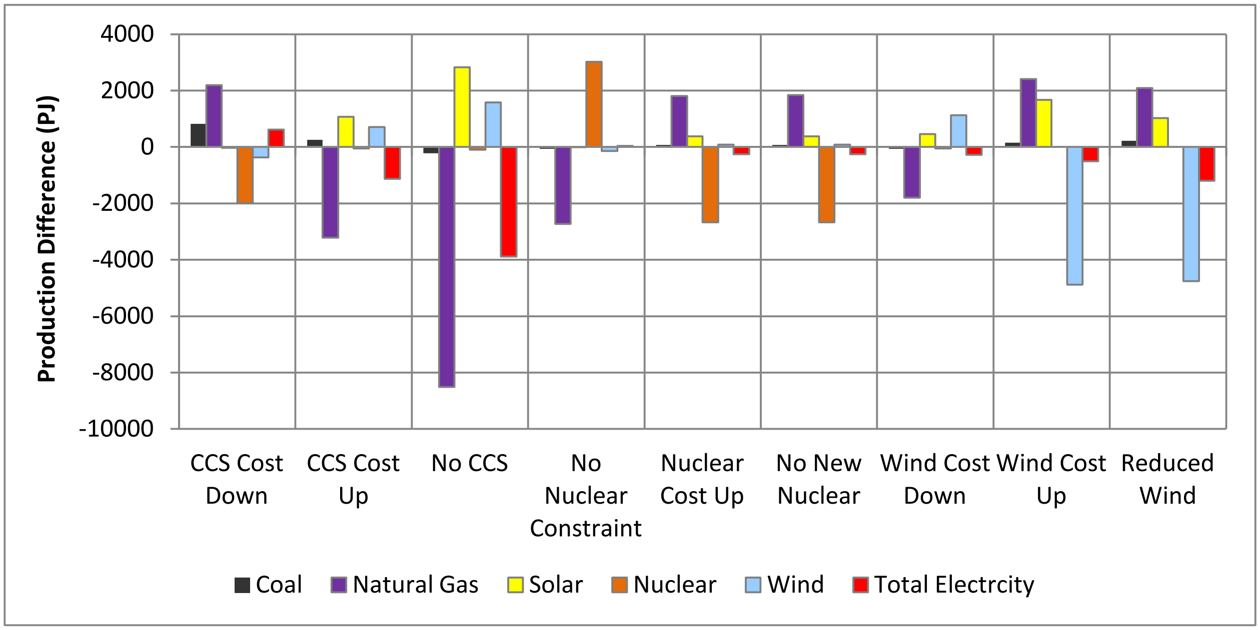
The *Wind Cost Down* scenario led to increased use of wind power in place of natural gas combined cycle with CCS. These changes resulted in the second largest decrease in water withdrawal at 0.69 trillion gallons of water (4% relative to the *50% CO_2 Reduction* scenario national total). Finally, the *Wind Cost Up* and the *Reduced Wind* scenarios led to similar, but not identical results. Both included an overall decrease in electricity generation (3% and 4% respectively relative to the *50% CO_2 Reduction* scenario national total). These scenarios both induced a decrease in electric vehicle use and an increase in biofuel and compressed natural gas vehicle use. Total electricity generation from wind power decreased 4877 PJ and 4758 PJ respectively (roughly 18% of the national total in the *50% CO_2 Reduction* scenario) but was partially compensated for by increased use of natural gas with CCS, solar and coal with CCS in both scenarios. These changes led to the largest increases in electric sector water withdrawal and consumption at roughly 4% of the total national water withdrawal and 15% of the national water consumption in the *50% CO_2 Reduction* scenario.

Implications

One of the most noteworthy takeaways of these scenarios is that changes in the availability or cost of a single electric sector technology can have major impacts on the transportation sector technology portfolio. In almost all the scenarios modeled, impacts on total electricity generation were paired with changes to electric transportation sector technologies such as the decrease in the use of electric vehicles and plug-in hybrids combined with an increase in the use of compressed natural gas vehicles and vehicles running on biofuels.

The *CCS Cost Up* scenario was the only one to cause an increase in total electric sector water withdrawal and a decrease in water consumption. All other scenarios produced changes in electric sector water withdrawal and consumption of the same sign (either negative or positive). Predictably, scenarios causing decreased use of wind (*Wind Cost Up* and *Reduced Wind*) were the scenarios causing the most substantial increase in national water withdrawal and consumption. The *No CCS* scenario, however, was the scenario causing the greatest decrease in total electric sector water use.

9A.



9B.

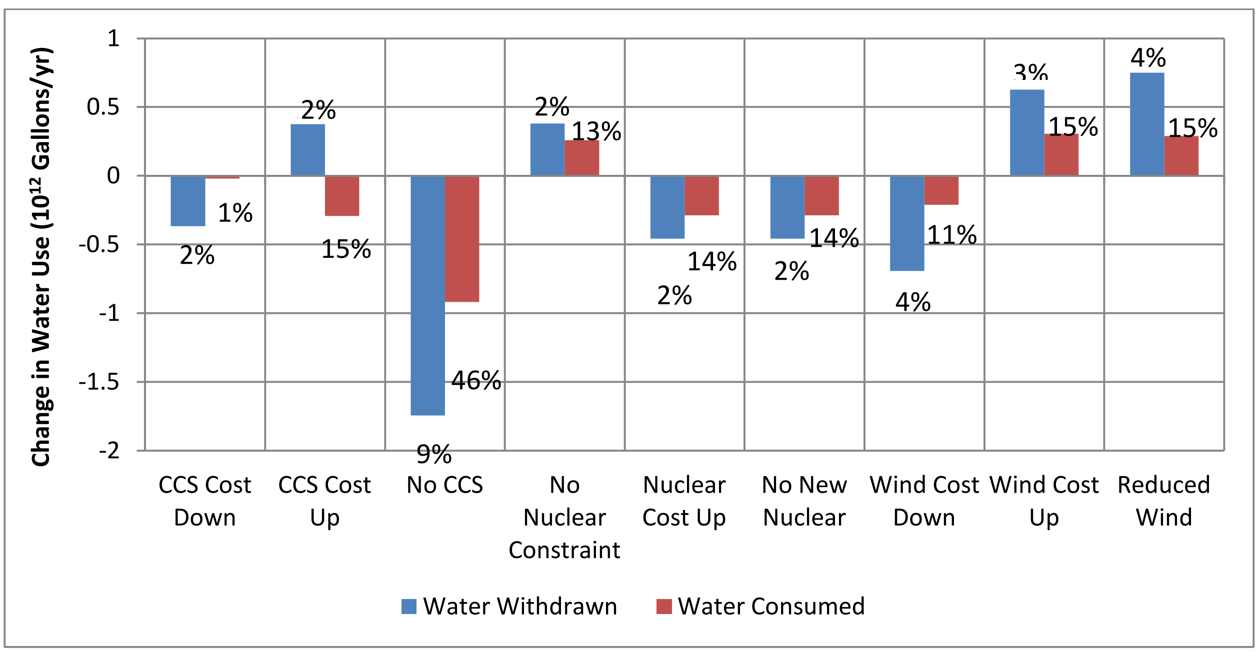


Figure 9. Sensitivity Analysis. Difference in electricity generation in 2055 between the 50% CO_2 Reduction Scenario and six sensitivity analysis scenarios for five major energy source categories (PJ) (9A). Difference in annual water withdrawal and consumption in year 2055 between the *50% CO_2 Reduction* scenario and six sensitivity analysis scenarios (9B). Percent change from the 2055 *50% CO_2 Reduction* scenario withdrawal and consumption are displayed next to each scenario.

VI. Conclusions

Constraints on U.S. energy system CO_2 emissions could have significant impacts on the water use of the electric sector. The model responded to CO_2 emissions constraints with electric sector technology changes that led to decreased overall water withdrawal in all scenarios. These changes also decreased water consumption under the *10% CO_2 Reduction* scenario, but led to an overall increase in water consumption under the *25%* and *50% CO_2 Reduction* scenarios in 2055. These changes in technology mix included decreased use of conventional coal and natural gas powered electricity generation and increased use of renewable technologies such as wind and solar, as well as nuclear power and natural gas combined cycle with CCS. In the *50% CO_2 Reduction* scenario, these changes were also driven by increased demand for electricity from the transportation sector resulting from vehicle electrification.

These technology changes and the associated decrease in total electric sector water withdrawal could significantly reduce aggregate national electric sector vulnerability to climate change. The decrease in total system water withdrawal that resulted under the CO_2 emission constraint scenarios reduces the potential for low stream flows and high water temperatures to impact electricity generating capacity. Moreover, the technology changes associated with these CO_2 constraints accelerated the switch from once-through cooling systems to recirculating cooling systems under our model assumptions. Recirculating cooling systems do not require the discharge of heated water back into ambient water bodies and thus are not susceptible to water-quality regulations that may prohibit cooling on hot days.

The increased aggregate national water consumption of the electric sector under CO_2 emissions constraints is less likely to impact electric sector vulnerability to climate change than is water withdrawal, but it could lead to different negative impacts. The electric sector currently accounts for only 6% of national water consumption, but that value is projected to almost double by 2055 in the *50% CO_2 Reduction* scenario.[1] As electric sector water consumption increases, competition with other water users such as agriculture and municipalities could lead to localized cooling water shortages and in extreme conditions, potentially result in localized electric power failures.

To interpret these results on a regional level, it will be critical to understand where climate change impacts on water resources are expected to occur. Previous regional analyses of future climate change impacts on water resources in the United States project that the most severe changes in water temperature highs and stream-flow lows will occur in south-central, south-eastern and mid-western states.[17,30] Our model results in western regions (regions 4, 7, 8 and 9) incorporated large wind power capacity under CO_2 constraints (especially 4 and 8) as well as solar thermal power (regions 7 and 9). These changes had the effect of driving both water withdrawal and water consumption down significantly in those regions, making them more resilient to variability in water resources and less susceptible to competition between users. This may be particularly valuable in region 7, which includes Texas and Oklahoma, where regional projections of decreased precipitation and increased water temperature are some of the most severe nationally.[17,30]

In contrast, eastern regions (regions 1, 2, 3, 5 and 6) met electricity demand primarily through nuclear power (most notably in region 5) and natural gas combined cycle with CCS (regions 2 and 3). As a result, water withdrawal decreased less in these regions relative to the national average, but water consumption rose dramatically in the *50% CO_2 Reduction* scenario. These changes would have the overall effect of decreasing electric sector vulnerability to changes in water resource availability in eastern regions. However, in light of the substantial projected climate change impacts on water resources in these regions (particularly in regions 3, 5, and 6), electric power reliability may still be threatened by climate change even under this most extreme CO_2 constraint scenario. Of these regions, region 5 would likely be the most vulnerable because of its heavy use of nuclear power and its associated water withdrawal.

In conclusion, these findings suggest that U.S. energy policies aimed at reducing total CO_2 emissions are likely to have complex impacts on the electric sector. The overall reduction in electric sector water withdrawal and increased penetration of low water-use technologies, such as wind and solar power, are likely to reduce electric sector vulnerability to climate change. However, in eastern regions where electric sector changes would be likely to incorporate higher water-use technologies, these benefits will be less significant. In addition, the increased water consumption resulting from the shift to recirculating cooling systems may lead to issues with electric power reliability as a result of competition with other users.

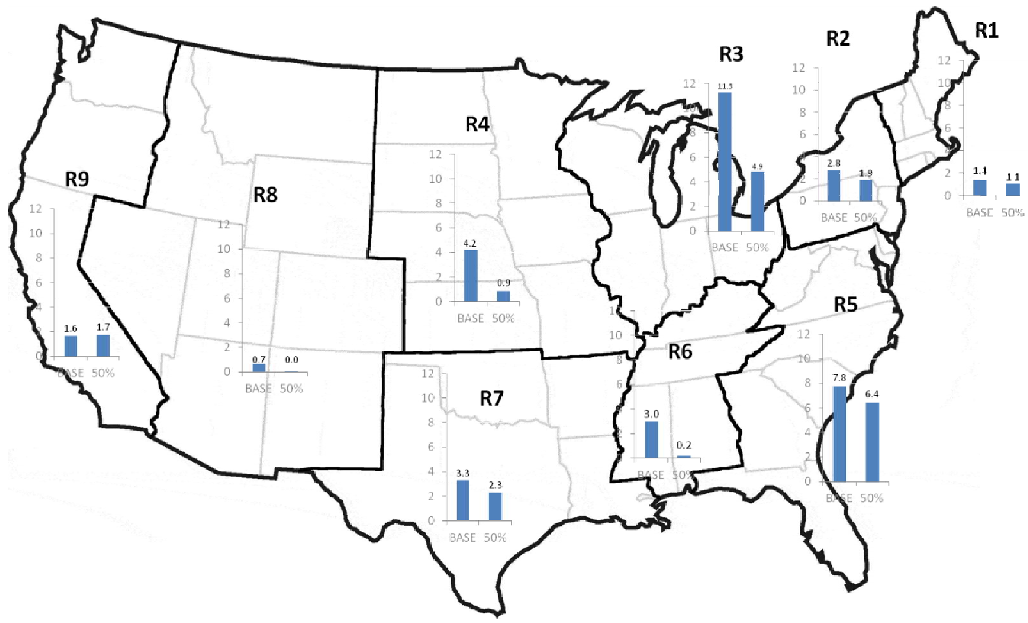
These conclusions must be considered in the context of the uncertainties and limitations inherent to the model and data sources. First, as an optimization model, MARKAL cannot predict how the U.S. energy system would develop under any policy scenario. Instead, MARKAL prescribes the most cost-effective system-wide solution based on the inputs it is given. As such, our results do not account for un-modeled factors such as consumer behavior, public opinion, and politics. These factors will likely have significant impacts on future energy choices that we cannot anticipate, especially for energy sources such as wind and nuclear power.

Second, there is uncertainty in the data used for this analysis. Model results are informed by AEO 2012 projections of demands, costs and available technologies. Although near term demands and technologies are relatively well characterized, the medium and long-term values are more uncertain. Future changes in the costs and efficiency of existing technologies, or the invention of new “breakthrough” technologies, could have dramatic effects on the energy choices the model makes as well as on the water use associated with those energy choices. Furthermore, AEO 2012 only provides projections on these variables out to 2035. As a result, 20 years of data are based on extrapolation of AEO forecasts for these variables.

Future extensions of this work could evaluate how alternative energy system responses to the same CO_2 constraints could impact electric sector water use. Possible alternative energy system responses could incorporate greater use of nuclear power, CCS or renewables relative to our current model results. In addition, future work could explore in greater depth the interactions between the electricity and transportation sectors.

Appendix A: Regional Water Use

10A.



10B.

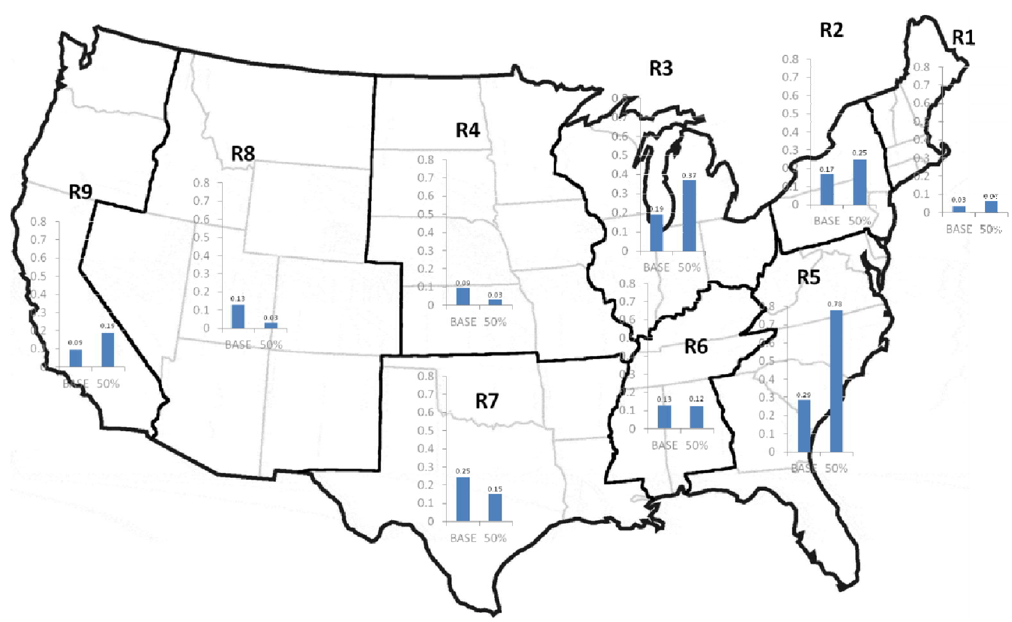
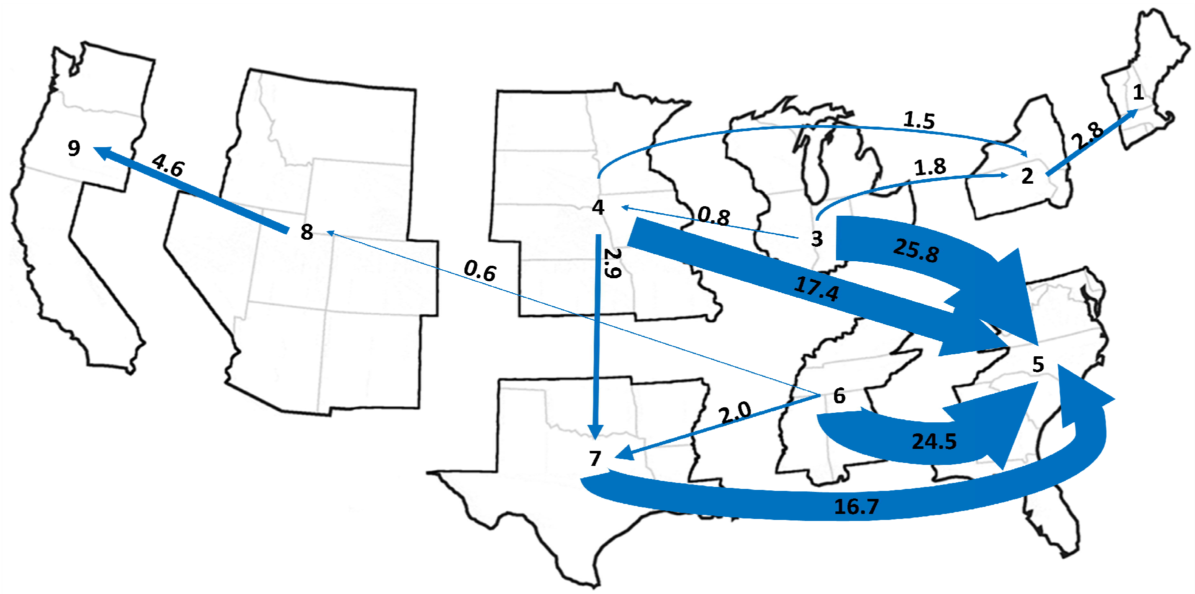


Figure 10. Water withdrawal in trillions of gallons for each region in 2055 for the *Base* (left bar) and the *50% CO_2 Reduction* scenarios (right bar) (10A).Water consumption in trillions of gallons for each region in 2055 for the *Base* (left bar) and the *50% CO_2 Reduction* scenarios (right bar)(10B).

Appendix B: Net Flows of Embodied Water

11A.



11B.

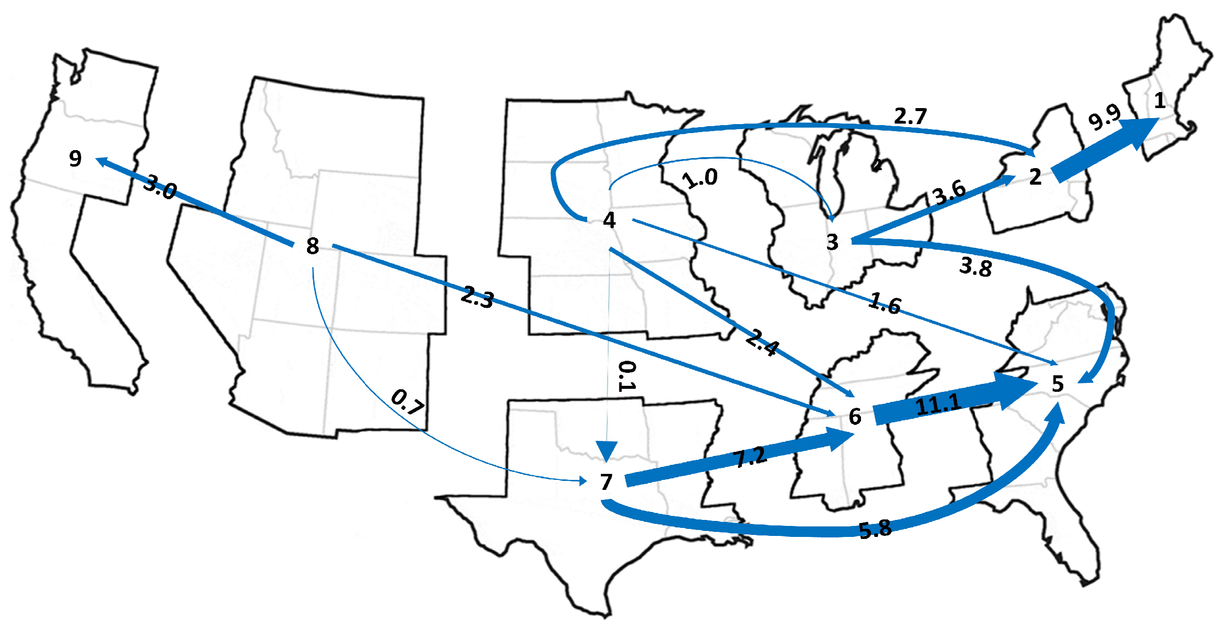


Figure 11. Net interregional flows of embodied water consumption (billion gallons/yr) in the *Base* scenario (11A). Net interregional flows of embodied water consumption (billion gallons/yr) in the *50% CO_2 Reduction* scenario (11B). Arrow sizes correspond to size of flow.

Appendix C: Water Use vs. Electricity Use by Region

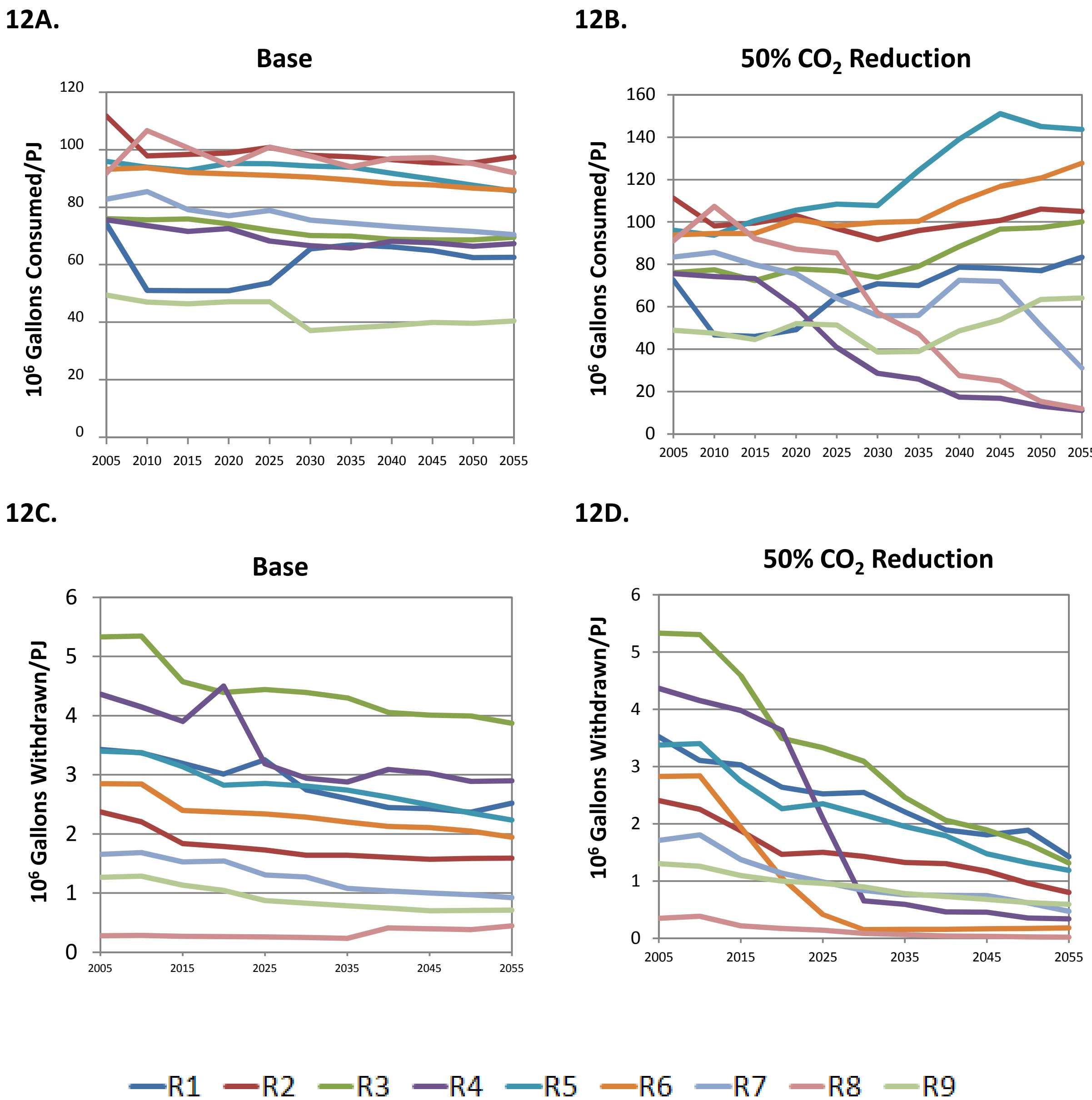


Figure 12. Water consumption per unit electricity generated (million gallons /PJ) for each region in the *Base* scenario (12A) and the *50% CO_2 Reduction* scenario (12B). Water withdrawal per unit electricity generated (billion gallons/PJ) for each region in the *Base* scenario (12C) and the *50% CO_2 Reduction* scenario (12D).

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