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Kustini LIM-WAVDE

Haibo ZHAI

Robert John KAUFFMAN
Singapore Management University, rkauffman@smu.edu.sg

Edward S. RUBIN

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Assessing carbon pollution standards: Electric power generation pathways and their water impacts

Kustini Lim-Wavde[a], Haibo Zhai[b,*], Robert J. Kauffman[a], Edward S. Rubin[b]

[a] School of Information Systems, Singapore Management University, Singapore 178902, Singapore
[b] Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA 15213, United States

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ABSTRACT

This study evaluates transition pathways in electricity generation and their future water impacts. Scenarios that do or do not comply with the carbon pollution standards – based on the U.S. New Source Performance Standards and Clean Power Plan – are evaluated. Using the Electric Reliability Council of Texas region as an illustration, the scenarios with carbon regulations are shown to have lower CO_2 emissions and water use from the power sector than the continuation of the status quo with more electricity generation from coal than natural gas. The benefits are due to increases in electricity generation from renewable sources and natural gas combined cycle (NGCC) plants plus retirements of existing coal-fired plants, which depend on natural gas and CO_2 allowance prices. When CO_2 is captured and sold for enhanced oil recovery with a price higher than $15 per short ton, water consumption is elevated because of more electricity generation from existing NGCC plants retrofitted with carbon capture and storage (CCS) technology. A stringent constraint on water withdrawals decreases electricity generation from existing power plants with once-through cooling, but increases overall water consumption because of an elevated share of plants with wet recirculating cooling systems in the fleet.

1. Introduction

To reduce greenhouse gas emissions for climate change mitigation, it is necessary to transition over time to a low-carbon electricity generation future. This may pose complex water supply challenges, as thermoelectric power plants are highly dependent on water, mainly for cooling purposes. Increasing droughts in some regions, such as in Texas in 2011 and California until mid-2016 (USDM, 2017), have exacerbated the water crisis. In 2010, the electric power industry made about 45% of total water withdrawals in the United States (Maupin et al., 2014). Without sufficient water supply, thermal generators will have to be shut down or curtail their operations (McCall et al., 2016). Thus, water should be an essential component of planning low-carbon electric power generation, especially in countries, states or regions with limited water resources (Zhai and Rubin, 2010).

Low-carbon energy options include fossil fuels with carbon capture and storage (CCS), renewables (wind and solar), and nuclear energy. Research has been conducted to explore the water impacts of low-carbon electric power generation at the plant, regional, and national levels. A shift to low-carbon electricity generation will either increase or decrease water use, depending on the choice of electricity generation systems and cooling technologies (Macknick et al., 2012a). Adding an amine-based CCS system for 90% CO_2 capture at a pulverized coal power plant using wet cooling towers nearly doubles water consumption (Zhai et al., 2011).

Macknick et al. (2012b) found that by 2030, the retirement of once-through cooling facilities will decrease national water withdrawals by 27–70% compared with 2010, whereas high penetration

Abbreviations: CC, Combined cycle; CCS, Carbon capture and storage; CCUS, Carbon capture, utilization, and storage; CEPCI, Chemical Engineering Plant Cost Index; CPP, Clean Power Plan; CPS, Carbon Pollution Standards; CPS + R, Carbon Pollution Standards with CCS retrofit; CPS + RW, Carbon Pollution Standards with CCS retrofit and water withdrawal constraint; CT, Combustion turbine; EFOR, Effective forced outage rate; EGU, Electric generating unit; EIA, Energy Information Administration; ELCC, Effective load carrying capacity; EOR, Enhanced oil recovery; EPA, Environmental Protection Agency; ERCOT, Electric Reliability Council of Texas; GJ/h, Gigajoules per hour; GW, Gigawatts; IECM, Integrated Environmental Control Model; IGCC, Integrated gasification combined cycle; IPM, Integrated Planning Model; kW, Kilowatts; kWh, Kilowatt hours; LCOE, Levelized cost of electricity; MW, Megawatts; MSCF, 1000 standard cubic feet; MWh, Megawatt hours; MWh-g, Megawatt hours-gross (all power output); MWh-net, Megawatt hours-net (less parasitic losses); NETL, National Energy Technology Laboratory; NREL, National Renewable Energy Laboratory; NG, Natural gas; NGCC, Natural gas combined cycle; NSPS, New Source Performance Standard; OG steam, Oil and gas steam; O&M, Operations & management; PC, Pulverized coal; PV, Photovoltaic; SCPC, Supercritical pulverized coal-fired; ST, Steam turbine; TSD, Technical support document; USDM, United States Drought Monitor; USGS, United States Geological Survey; WACC, Weighted average cost of capital

* Corresponding author.
E-mail address: hbzhai@cmu.edu (H. Zhai).

of coal-fired plants with CCS and nuclear plants will increase them by about 22% by 2050 compared with the 2010 level. In contrast, Tidwell et al. (2013) found that national water withdrawals may increase by roughly 1% or decrease by up to 60% relative to 2009 levels, while the change in national water consumption will range from −28% to + 21%, depending on the implementation of CCS retrofit and a CO_2 emission price. However, Webster et al. (2013) found that a deep reduction requirement for CO_2 emissions will increase regional water withdrawals for electricity generation in the Electric Reliability Council of Texas (ERCOT) region because of additional water withdrawals for nuclear generation. Also, simultaneous constraints in both CO_2 emissions and water withdrawals will result in a different grid mix with a higher fleet cost of electricity generation, compared to a single constraint on CO_2 emissions (Macknick et al., 2015; Chen et al., 2013; Qin et al., 2015).

Carbon pollution regulations will aid in limiting CO_2 emissions and facilitating the transition to low-carbon electricity generation. In 2015, the U.S. Environmental Protection Agency (EPA) established the New Source Performance Standards (NSPS) for limiting CO_2 emissions from new fossil fuel-fired electric generating units (EGUs) (U.S. EPA, 2015a). Under Section 111(d) of the Clean Air Act, the U.S. EPA also issued the Clean Power Plan (CPP). It was intended to establish standards of performance for CO_2 emissions from existing EGUs, to cut sector CO_2 emissions by 32% by 2030 from their 2005 levels (U.S. EPA, 2015b). CO_2 emission reductions can be achieved by three suggested building blocks: (1) improving the heat rate of existing coal-fired power plants; (2) increasing generation from existing natural gas plants; and (3) increasing generation from new renewable energy sources (EPA, 2015b). Although retrofitting the entire existing fleet of power plants with CCS technology is not practical, it may be feasible for some coal-fired EGUs (Zhai et al., 2015; Talati et al., 2016). Although the Trump Administration indicated in 2017 its intention to renege on the CPP, it currently remains in force. States have the authority to manage their electric power grids. So, it is important to examine the consequences of possible planning pathways. The current analysis therefore remains instructive even if superseded by later changes in policy.

Planning low-carbon electricity generation pathways in a cost-effective, carbon regulation-compliant, and sustainable manner is important for the electric power sector. The goal of this study is to examine the possible transition pathways for power capacity expansion, while targeting compliance with regulations on the low-carbon pathways or the non-compliant pathways. Each pathway represents a scenario describing a possible expansion of the power system in the future. The business-as-usual (BAU) scenario is the pathway that continues without trying to implement the carbon pollution regulations in a meaningful way. The low-carbon scenarios are those that can comply with carbon pollution regulations by retrofitting CCS to existing coal-fired and NGCC plants or increasing generation from natural gas and renewables or low-carbon technologies.

The overarching research question is: How does each of the pathways affect water use for electricity generation? We further ask: What are the water impacts of complying with the carbon regulations? If retrofitting CCS to existing plants is considered, how will it affect electricity generation and water use? Additionally, how will water availability affect electricity generation under the carbon constraint and the choice of low-carbon and cooling technologies? To address these questions, this study comparatively examines the technological mix and water use of alternative pathways toward an energy future with or without carbon regulations.

In Texas, the electric power sector accounted for 36% of total state-level water withdrawal in 2005 (Kenny et al., 2009). This state experienced severe droughts in the past years (USDM, 2017), which has increasingly limited the availability of water resources for the electric power and other sectors. ERCOT in Texas manages a power grid for 90% of the state's total electricity supply (ERCOT, 2015a, 2016).[1] Hence, is the region chosen for this case study-based scenario analysis.

2. Carbon regulations on existing and new power plants

The NSPS limits CO_2 emissions to 1400 lb CO_2/MWh-g for new coal-fired EGUs and 1000 lb CO_2/MWh-g for new natural gas-fired EGUs or 1030 lb CO_2/MWh-g for base load natural gas-fired EGUs (U.S. EPA, 2015b). To meet the emission limit, new supercritical pulverized coal-fired (SCPC) power plants have to reduce emissions by about 20% by requiring CCS for partial CO_2 capture (Ou et al., 2016). However, there is no need for CO_2 emission reductions at new NGCC power plants.

The CPP aimed to establish national emission performance standards for existing fossil fuel-fired EGUs. The rules present state-specific rate-based goals and equivalent mass-based goals, reflecting their power generation mix in 2012. States are flexible to choose the emission compliance plan and mitigation measures, so this study focuses on mass-based compliance as it relatively easily controls overall emissions. For such a plan, each state must implement a cap for the allowable CO_2 emission level that is distributed across the existing affected EGUs. The affected sources include coal, steam from oil and gas, and natural gas (combined cycle) that were in operation or commenced construction as of January 8, 2014. They had to meet two criteria: serve a generator capable of selling greater than 25 MW to a utility power distribution system; and have a base load rating of greater than 260 GJ per hour (U.S. EPA, 2015b). In the mass-based plan without a CO_2 emissions cap for new sources, the state should address the potential generation leakage to new fossil fuel-fired sources.

To mitigate the risk of leakage, the U.S. EPA proposed set-aside allowances, such as the Clean Energy Incentive Program (CEIP) for rewarding early emission reduction projects (U.S. EPA, 2016), as well as output-based set-asides to incentivize existing NGCCs to increase their utilization (U.S. EPA, 2015c), and renewable set-asides to mitigate the leakage of CO_2 emissions to new NGCCs (U.S. EPA, 2015d). Assuming a national average allowance price of $13 per short ton, the EPA estimated that 5% of the total allowance represents a reasonable renewable set-aside level to mitigate the impacts of the transition (U.S. EPA, 2015d).

This study also considers renewable set-asides and output-based set-asides. With their implementation, the total allowance for the existing EGUs is the mass-based target minus the set-asides. Under the CPP, the total allowance was to be assigned proportionately to each unit's share of state-level historical generation (U.S. EPA, 2015c). The EPA also proposed an allowance trading program between the affected existing EGUs and renewable units within a state or with other states (U.S. EPA, 2015e). But, a recent study (Van Atten, 2016) showed that the EPA's proposed approach for allocating allowances in a program for existing plants may have a minor impact on emissions leakage to new fossil-fired power plants outside the program. So, we use the mass-based approach which limits such new-source emissions.

The EPA also estimated new source emissions based on meeting electricity demand in 2030 (U.S. EPA, 2015f). The incremental generation needed was calculated using the projected load growth from 2012 minus the estimated generation from facilities under construction and generation growth in the affected EGUs and incremental renewable energy. Using the NSPS emission rate for NGCCs (1030 lbs/MWh), the incremental generation needed to satisfy new electricity demand was converted to new source emissions. ERCOT's mass-based emission target is 157 million (M) short tons. This is calculated by summing the allocated CO_2 allowances of ERCOT's existing EGUs proposed by the EPA (U.S. EPA, 2015c) plus the estimated set-aside allowances. Detailed

[1] Other electricity in Texas is from Western Elec. Coordinating Council, Southwest Power Pool, and Southeastern Elec. Reliability Council (Public Utility Commission of Texas, 2013). These are excluded: the ERCOT grid is managed separately.

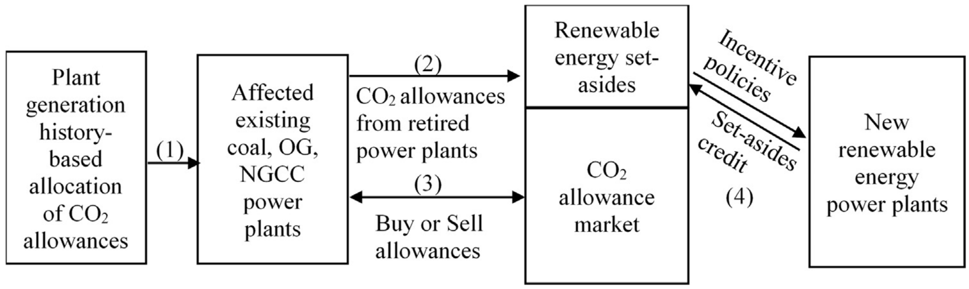


Fig. 1. CO_2 Allowance trading scheme. Notes. (1) The CO_2 allowances are distributed to affected existing coal, OG, and NGCC power plants based on the unit level share of annual average generation from 2010 to 2012. (2) When an affected existing unit retires, its allocated allowances are transferred to renewable set-asides. (3) Affected existing units can buy or sell allowances from or to the allowance market. (4) The allowances in renewable set-sides incentivize electricity generation from new renewables via set-aside credits.

allocations of emission allowances for the affected existing EGUs aggregated by electricity generation sources and cooling systems are in Appendix Table A1. Using the EPA's approach (U.S. EPA, 2015f), new source complements will be about 3.9 M short tons for the ERCOT region.

For set-asides, the approach outlined in the EPA's mass-based federal plan (U.S. EPA, 2015c) was adopted. Existing NGCCs with an average capacity factor of more than 50% are eligible to receive an allowance from set-asides. As the EPA assumed that the set-asides would incentivize the affected NGCCs to increase their generation to 60% of capacity, their output-based set-aside is calculated as follows: Baseline existing NGCC capacity × 10% × 8760 h × 1030 lb/MWh-net × 1 / 2000 (U.S. EPA, 2015c). Using this formula, the output-based set-aside for existing NGCCs in the ERCOT region is estimated at 15.8 M short tons. The optimal allocation of this set-aside to existing NGCC plants will be determined by the generation capacity expansion model presented later. The renewable set-aside for the ERCOT region is assumed to be 5% of total CO_2 allowances, or about 7.8 M short tons.

The allowance and set-aside trading mechanism is demonstrated in Fig. 1. Existing coal, oil and gas, and NGCCs can buy CO_2 allowances from the renewable set-aside pool or from the allowance market. If an EGU has an excess CO_2 allowance, it can be sold in the allowance market. The total revenue from selling allowances from renewable set-asides is distributed as credits to incentivize generation from new renewables. The incentive rate is set as the difference in levelized cost of electricity[2] between new NGCC and wind plants so that renewables are competitive with new NGCC plants. If any existing plants retire, their allowance will be reallocated to renewable set asides as proposed by EPA (2015c), so the set-aside pool can be higher than 5% of the total allowance.

3. Assessment framework and data sources

3.1. Framework and problem orientation

Fig. 2 illustrates the integrated electricity-water planning and assessment framework. Although this framework is applied to assess the ERCOT region, it is also applicable for other states and countries. The parameters are customizable to estimated electricity demand, fuel prices, and existing EGUs related to the targeted geographic scope for the analysis.

With the goal of minimizing the fleet's net cost of electricity generation, this research uses an electricity capacity expansion model as a basis for optimizing investments in capacity with low-carbon energy technologies and determining the optimal grid mix, capacity retirement, and CO_2 allowance purchases and sales. The optimization includes constraints for the fleet of plants, as described in Fig. 2. The generation technologies include conventional fossil fuel-fired power plants (coal, oil and gas, and natural gas), coal and natural gas-fired power plants with CCS, and nuclear and renewable energy power plants. The cooling technologies include once-through, recirculating (wet), dry, and hybrid (wet-dry) cooling. The systems considered for new capacity expansion are: SCPC, SCPC with CCS, integrated gasification combined cycle (IGCC), NGCC, NGCC with CCS, gas CT, nuclear, wind, and solar photovoltaic (PV) technologies. Given EPA's regulations on cooling water intake structures, no new capacity will use once-through cooling.

3.2. Data sources, collection and measures: technologies and metrics

We obtained performance and cost information on power generation and cooling systems from the U.S. Energy Information Administration (EIA) and the National Energy Technology Laboratory (NETL), plus results from power plant modeling.[3] Appendix Tables B1, B2 and B3 summarize these metrics. For new PC, IGCC, and NGCC power plants with and without CCS for 90% CO_2 capture that use wet recirculating systems, the estimates of heat rates, CO_2 emissions, and water withdrawal and consumption rates, as well as capital, fixed and variable O&M costs were adopted from NETL's (2013) baseline report.[4] For nuclear, gas combustion turbines, and hydropower systems, EIA's (2013) capital and operating cost estimates are used. For wind and solar power, the cost assumptions in 2030 for renewables in the EPA's (2015h) Base Case v.5.15 in the Integrated Planning Model (IPM) are used. For nuclear power, the heat rate reported in Webster et al. (2013) was adopted. All cost assumptions and results are in 2012 dollars unless stated otherwise.

The effective load carrying capacity (ELCC) percentage is used to account for the effective generation capacity that can be counted on during peak periods (Garver, 1966). Similar to Webster et al. (2013), ELCC is assumed to be 100% minus the effective forced outage rate (EFOR) for thermoelectric units (nuclear, coal, gas combustion turbines, and hydro). It is set at 100% for NGCC plants because EFOR can be offset by duct-firing capabilities that enable higher-than-rated output generation during peak periods (Chase and Kehoe, 2000). For hydropower, it is assumed to be 93.4% due to EFOR at 6.6% (U.S. EIA, 2014), however, the annual load of hydropower may be lower depending on water resource availability. The ELCC factor for wind power in Texas averages 24% for the coastal and west regions (ECCO International, 2013). The ELCC factor for solar power in Texas is assumed to be 22%, based on the solar reserve margin contribution of Texas in the EPA's (2015h) IPM documentation. The ELCC is the same regardless of the cooling system type.

For a given power plant, the choices of cooling technology and CCS system have effects on plant capital and O&M costs (Zhai and Rubin, 2010, 2016). To account for the effects of CO_2 capture efficiency and cooling technology on EGU cost and performance, the Integrated Environmental Control Model (IECM v9.1) developed by Carnegie Mellon

[2] See Appendix E for the calculation details.

[3] These are used to determine the cost and performance metrics of the power plant technologies including new plants (23 types), existing plants (14 types), and existing PC and NGCC plants with CCS retrofits (1 and 3 types, respectively).

[4] Since this report uses costs in 2007 dollars, the costs were converted into 2012 dollars using the Chemical Engineering Plant Cost Index (CEPCI) (Chemical Engineering, 2017).

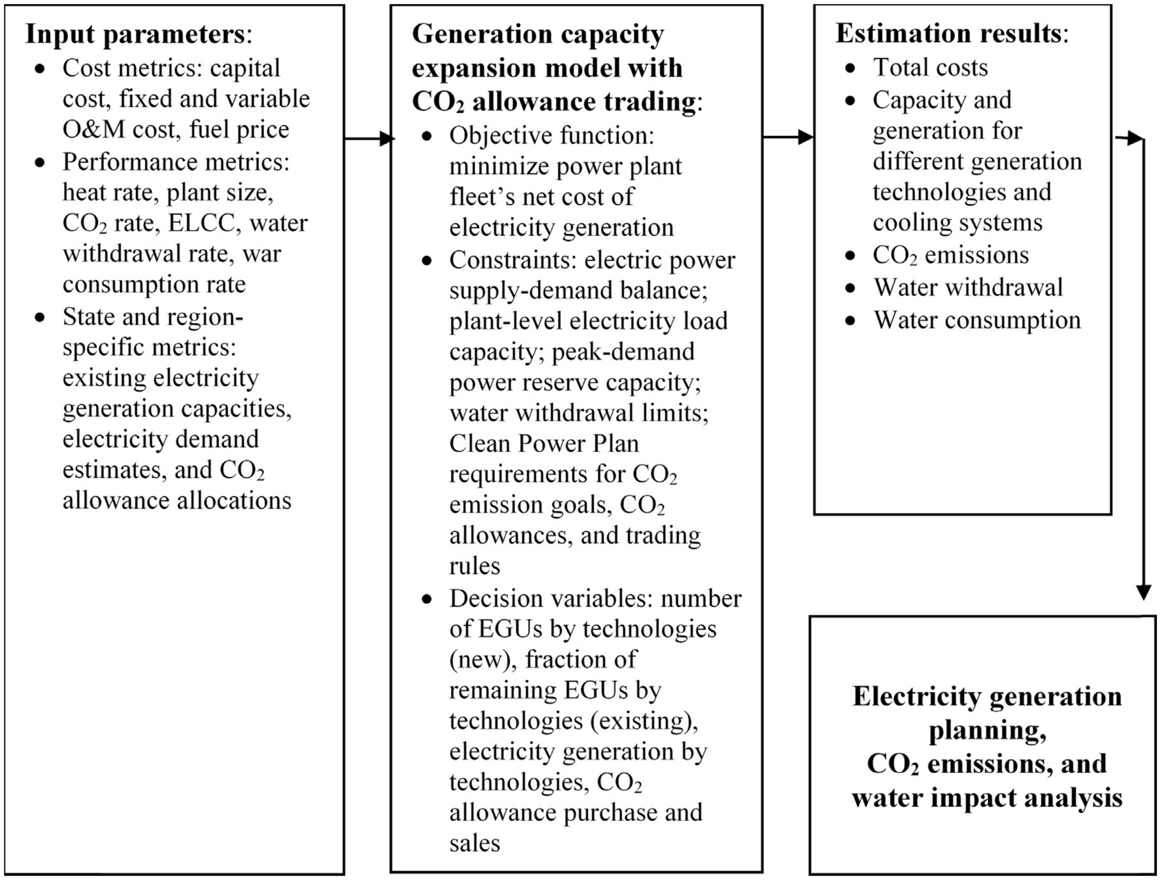


Fig. 2. An integrated electricity-water planning and assessment framework.

University is used to derive various correction factors to adjust the base plant water use, heat rate, and costs.[5]

IECM is also applied to model new PC plants: an SCPC plant without CCS, with CCS partial capture of CO_2 according to the relevant CO_2 emission standards, or with CCS for 90% CO_2 capture using recirculating, hybrid, and dry cooling systems. Compliance with the CO_2 emission standard of 1400 lb per MWh gross involves about 20% CO_2 capture at new SCPC plants. For plants with hybrid cooling, the cost and performance correction factors were estimated based on Zhai and Rubin's (2016) study. The results for these plants are in Appendix Table C1. By using the results for a PC plant with recirculating cooling without CCS as the benchmark, the next derivation was for correction factors for capital and O&M costs, and heat and water use rates of new PC plants with partial CCS with recirculating, hybrid, or dry cooling, and with or without CCS with hybrid or dry cooling.

Similarly, IECM is used to assess the performance and costs for new NGCC plants, including those plants without CCS and other plants that implement CCS with recirculating, hybrid, or dry cooling. Appendix Table C2 offers the results for new NGCC plants and correction factors for capital, O&M costs, and heat rates for new NGCC with or without CCS using hybrid and dry cooling.

IECM is also used to estimate the performance and costs for existing PC and NGCC plants, including CCS retrofits. The plant specification and modeling results are provided in Appendix Tables C3 and C4. When CCS is retrofitted to existing plants, a retrofit factor of 1.25 for the CCS capital costs was applied to account for additional costs from difficulties in access to various plant areas and in integrating the CCS system into the plant (NETL, 2013; Zhai et al., 2015).[6]

The water withdrawal and consumption rates of nuclear, PC, and NGCC plants with once-through and recirculating cooling, and NGCC plants with dry cooling are based on the average water use factors from Macknick et al. (2012a). For other generation technologies, the rates are estimated using the correction factors derived from the water withdrawal rate ratio in Webster et al. (2013). Appendix Table D1 summarizes the factors for the costs, heat rates, and water use rates.

3.3. Data Sources, Collection and Measures: State-Level

A technical support document from the U.S. EPA (2015g) provides information on plant-level existing fleet capacity in the ERCOT region of Texas in 2012 (U.S. EPA, 2015g). With additional information of the cooling systems used for these EGUs from the U.S. Geological Survey report (Diehl and Harris, 2014), the capacity and historical generation of these EGUs were aggregated by generation technologies and cooling systems, as shown in Table 1.

Overall, 42% of ERCOT's existing fleet capacity uses recirculating cooling, 7.8% uses hybrid cooling, and 2.5% uses dry cooling, whereas 29% of the fleet capacity uses once-through cooling. The average plant

[5] IECM (2015) is a power plant modeling tool developed to provide estimates of the performance, water use, emissions, and costs for fossil-fuel fired power plants with and without CCS.

[6] The IECM results show that, for a fully-amortized subcritical PC plant and an NGCC plant (GE 7FA) with recirculating cooling, the retrofit costs for full CCS are $1409 and $696 per kW, respectively. Due to the additional parasitic load of the CCS system, the plant net capacity of an existing coal plant with CCS retrofit decreases from 550 MW to 468 MW. Similarly, the net capacity of an NGCC plant with a CCS retrofit decreases from 400 MW to 344 MW. These results were then used to derive the correction factors for the capital, fixed and variable O&M costs, and heat rate of existing PC and NGCC plants with once-through cooling, and for existing PC or NGCC plants with CCS retrofits with recirculating cooling, and existing NGCC plants with CCS retrofits with hybrid or dry cooling.

Table 1
Existing generator capacity and electricity generation, ERCOT in 2012.[a,b,c]

Technology/cooling system	Capacity (GW)	Generation (M MWh)
Coal/Once-Through	12.3	68.0
Coal/Wet-Recirc	8.7	42.2
OG Steam/Once-Through	13.4	7.1
OG Steam/Wet-Recirc	2.7	0.9
NGCC/Once-Through	3.0	11.0
NGCC/Wet-Recirc	29.4	107.4
NGCC/Hybrid	1.0	1.9
NGCC/Dry	1.7	4.9
Wind	11.2	29.4
Solar Photovoltaic	0.1	0.1
Nuclear/Once-Through	2.4	19.9
Nuclear/Wet-Recirc	2.7	18.5
Gas CT	5.5	5.8
Hydropower	0.6	0.5
Total Capacity	94.5	317.7

[a] Capacity and generation of EGUs in ERCOT for affected fossil-fuel-fired, existing gas CT, renewable EGUs (U.S. EPA, 2015g); the generation of unaffected fossil fuel-fired EGUs was about 9.3% of ERCOT's total electricity generation (U.S. EPA, 2015g).

[b] USGS plant water use for EGU cooling, 2010 data (Diehl and Harris, 2014).

[c] Some cooling technology info available from the Internet, EIA Electricity Data Browser and 2013 EIA-923 database.

heat rate for existing plants is 11.2 MMBtu per MWh for coal-fired EGUs, 12.2 MMBtu per MWh for OG steam plants, and 7.8 MMBtu per MWh for NGCC plants. See Appendix Table B2 for a summary of their costs, CO_2 emissions, and water withdrawal rates.

Fuel prices were estimated based on EIA's projections.[7] A recent load loss study (ECCO International, 2013) further reported that ERCOT's target reserve margin is 16.1%, which was adopted for the planned power reserve margin. The electricity demand projection was made based on historical loads, using ERCOT's electricity 8,760-h demand data to build a load duration curve with peak demand of 65 GW in 2012 (ERCOT, 2015b). The load was adjusted to have the total generation of 318 MM MWh as in Table 1. A scale factor of 1.174 was then applied uniformly to develop the predicted load duration curve shown in Fig. 3 that represents the demand load in 2030.[8]

4. Modeling electricity generation capacity expansion

4.1. Optimization model for energy planning

A static capacity expansion model developed by Webster et al. (2013) was expanded and applied by including CO_2 emissions allowance trading, renewable and output-based set-asides, and consideration of EOR and CCS retrofits. Our model distinguishes between new and existing EGUs subject to the CO_2 emission standards, including CO_2 emission allowances and set-aside trading, and allows unit retirement. The objective is to minimize the total net cost of the power generation fleet that accounts for total fleet costs minus total offsets. The fleet costs include capital investment, fixed and variable operating costs, fuel costs, CO_2 emission allowance costs, and CO_2 transport and storage costs. The offsets include cash flows for selling CO_2 captured by CCS for enhanced oil recovery (EOR) and excess CO_2 and renewable set-aside allowances. The model is presented in Appendix E.

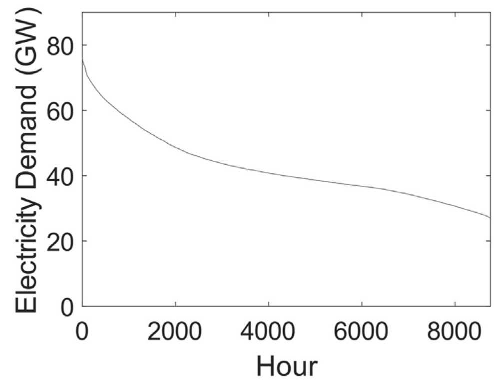


Fig. 3. Predicted load duration curve for ERCOT electricity demand in 2030. Notes. The load duration curve was scaled up by 1.174 from the load duration curve in 2012 (ERCOT, 2015a), which was adjusted to ERCOT's historical generation (U.S. EPA, 2015g).

This model uses mixed integer-linear programming with simplified operations of economic dispatch for an 8,760-h load duration curve (Webster et al., 2013). Each generation technology is assumed to have the same maximum capacity size in the model. The decision variables include the number of new EGUs for each generation technology and the amount of generation for each of the demand blocks in the load duration curve.[9] In addition, a decision variable determines the remaining fraction of existing EGUs if any existing EGUs are retired. The model also includes variables for the amount of CO_2 allowances purchased and sold in allowance trading associated with the CPP's mass-based compliance plan. It has five types of constraints on the fleet in each operating period: (1) electricity demand and supply balance; (2) load capacity for minimum and maximum load generation; (3) reserve electricity generation capacity; (4) Clean Power Plan compliance for CO_2 emission allowances and EPA emission trading rules[10]; and (5) a water withdrawal limit when applicable.

4.2. Simulation scenarios

To examine the effects of carbon emissions and water use limits on the future power grid, Table 2 summarizes the scenarios for comparison, including the business-as-usual (BAU) scenario without any carbon policy and water use constraints, and the three low-carbon scenarios.

The BAU scenario serves as the case for comparison that meets electricity demand; it does not consider the policy constraints on CO_2 emissions and water withdrawal. The Carbon Pollution Standards (CPS) scenario simulates the implementation of the CPP to achieve the CO_2 emission mass-based goal for existing plants in 2030. Amine-based CCS is employed for partial CO_2 capture at new coal-fired plants to meet the CO_2 NSPS. It adopts building blocks identified by CPP. It also takes into account the total CO_2 emission limit for affected existing and new EGUs. Although CCS retrofit is not identified by the CPP as one of the sector-wide mitigation measures, it could be viable for significantly

[7] The average natural gas price for ERCOT plants was $3.00 per MMBtu in 2012 (U.S. EIA, 2012) and is projected to be $4.93 per MMBtu in 2030 in terms of the U.S. national annual fuel price growth rate of 2.8% (U.S. EIA, 2015a). The average coal price for ERCOT plants was $2.16 per MMBtu in 2012 (U.S. EIA, 2015b) and is expected to be $2.49 per MMBtu in 2030 for an annual growth rate of 0.8% (U.S. EIA, 2015a). The price of nuclear fuel was $0.29 per MMBtu in 2012 and is assumed to be $1.01 per MMBtu in 2030 (U.S. EIA, 2013a).

[8] The scale factor was estimated in terms of the expected 17.4% increase in Texas' net electricity generation from 2012, assuming 0.8% annual growth (U.S. EPA, 2015g; U.S. EIA, 2015b).

[9] A smooth form of the *load duration curve* represents a one-year period of electricity demand, with 8760 hourly load observations in descending order to populate a cumulative distribution function. Then, to support numerical simulation and enhance computational performance in this research, the duration load curve of load-ordered observations was *discretized*, so a year was composed of 438 *load strips* (Sherali et al., 1982) of 20 h each (with 438 load strips · 20 h = 365 days · 24 h = 8760 h, the number of hours in one year.) The *average hourly demand load* in each strip was used, as in other power system planning research (e.g., Roh et al., 2009; Baringo and Conejo, 2011). The exception is the left-most load strip in the curve – the *peak strip*, which contains the highest load observations; for this, *hourly peak demand load* was used.

[10] The integer programming and simulation model was created in MatLab R2015a (MathWorks, 2015).

Table 2
Summary of alternative energy scenarios in 2030.

Scenario	NSPS, CPP, mass-based, new source complements target	CCS retrofit option?	Constraint on water withdrawal?
BAU	No	No	No
CPS	Yes	No	No
CPS + R[a]	Yes	Yes	No
CPS + RW[a]	Yes	Yes	Yes

[a] Allowance trading in our model has not considered incentive scheme to existing plants with CCS retrofits for reducing their CO_2 emission.

reducing CO_2 emissions from some existing fossil fuel-fired power plants under some circumstances (Zhai et al., 2015). Economic incentives are expected to promote the growth of CO_2 capture (Talati et al., 2016; Johnson, 2018). To investigate whether and when CCS retrofit is a feasible measure in complying with carbon pollution standards, as well as its potential impact on water use, the CPS + R scenario is presented in parallel with the CPS scenario, which includes the option of retrofitting amine-based CCS for 90% CO_2 capture to existing coal and natural gas-fired plants.

Because limits on water availability may affect the choice of low-carbon technologies in meeting the CO_2 emission limits, the CPS + RW scenario includes an additional constraint on water withdrawal. The drought in Texas in 2011 decreased the state-wide reservoir water storage by about 30% from October 2010 to the minimum in November 2011 of approximately 23.2 cubic kilometers (Scanlon et al., 2013), for example. For events like this, the CPS + RW scenario aggressively limits water withdrawal for low-carbon electricity generation to 50% of Texas' annual freshwater withdrawal. This was 3833 billion gallons (bn gals) in 2010 (Maupin et al., 2014).

5. Results: power generation pathway scenarios and water impacts

5.1. Major assumptions for scenario analysis

Table 1 summarizes the existing power capacity and electricity generation in 2012; Fig. 3 presents the projected load duration curve in 2030; Appendix A presents the CO_2 allowance allocations for affected EGUs; and Appendix B covers the technical and economic metrics for new and existing power generation and cooling systems. The other major assumptions for projecting the electricity generation fleet in 2030 are given in Table 3.

5.2. Scenario results and analyses

Next presented are electricity capacity and generation projections under the different future scenarios that are based on the aforementioned assumptions. In addition, the model was also applied to estimate the fleet generation in 2012. Table 4 compares electricity capacity and generation mix by fuel for the scenarios.

Although electricity generation in 2012 was estimated based on average fuel prices and unit attributes (U.S. EIA, 2012, 2013a), the generation profile is close to the historical record: 12.1% nuclear, 34.7% coal, 41.2% natural gas, 2.5% OG, 9.2% wind, 0.0% solar, and 0.2% water (U.S. EPA, 2015g).[11] Table 5 compares the total annual cost, capacity, electricity generation, CO_2 emissions, water withdrawal, and water consumption. Different from the future scenarios, the total annual cost of the 2012 scenario only includes O&M and fuel costs due to the assumption that the existing fleet is fully amortized. Appendix Table F1 provides generation shares by plant type for different cooling technologies.

Overall, the total CO_2 emissions from the regional power sector will increase by 33% in 2030 under the BAU scenario without any carbon regulations and incentives for renewables. Compared to 2012, the total water withdrawal will increase by 25%. For the given fuel assumptions, the future capacity and generation from coal under BAU is higher than in 2012 due to the cheaper generation cost of existing coal-fired EGUs compared to gas-fired EGUs. The low-carbon pathways will have similar total water use in 2030 relative to 2012. But their total CO_2 emissions will be lower than in 2012. Due to carbon regulations, the capacity and generation from natural gas, wind, and solar in the low-carbon scenarios are higher than for BAU. Electricity generation from EGUs with once-through cooling is 32% in the BAU, 33% in CPS and CPS + R, and 17% for CPS + RW. Existing coal-fired, once-through cooled EGUs contribute the most water withdrawal in the power sector. Water consumption is much higher for BAU than the low-carbon scenarios. Comparing the low-carbon scenarios, the simultaneous constraints on CO_2 and water withdrawal will lead to increased water consumption because of the elevated share of wet recirculating cooling technology in the fleet.

Table 4 and Fig. 4a show the BAU results. In 2030, 6.7 GW of NGCC plants will be added to meet generation demand. Without retirement and addition of coal capacity, the average capacity factor of coal-fired plants will increase to 93%, and generation will be 41% by coal and 38% by natural gas.

The CPS and CPS + R scenarios have the same results because without economic incentives, no CCS is retrofitted to existing plants in the CPS + R scenario. Fig. 4b shows that 12 GW of new capacity from NGCC plants is needed to meet regional electricity demand while adhering to the emission cap. About 8.7 GW of existing coal EGUs are estimated to retire. Compared to BAU, the generation from coal is 62% lower, but the generation from natural gas is 50% higher. The renewable set-asides provide economic incentives to increase capacity from new renewable EGUs to about 10 GW. Also, the resulting generation shares of wind and solar sources increases to 13% and 3%.

With the water withdrawal limit set to 50% of Texas' 2010 level (1900 bn gals), the CPS + RW results indicate that 4.1 GW of coal EGUs with once-through cooling and 4.9 GW of coal EGUs with recirculating cooling will be retired. As shown in Fig. 4c, generation from existing coal and NGCC plants with once-through cooling will decrease by 30 M MWh and 19 M MWh, respectively.

In the scenarios without a constraint on water withdrawal, generation from thermoelectric plants is estimated to be 32–33% for plants with once-through cooling and 63–66% for recirculating cooling with small shares for hybrid and dry cooling. The scenario that limits water withdrawal is estimated to have lower electricity generation at 17% from plants with once-through cooling, and more generation at 82% from plants with recirculating cooling. Electricity generation from plants with hybrid and dry cooling will not change very much.

[11] For the future scenarios, 2 GW of existing capacity from coal-fired EGUs with once-through cooling were excluded to reflect the scheduled retirement of multiple coal-fired Monticello EGUs in Texas in 2018 (Power Engineering, 2017). Just a week after the retirement announcement, the Big Brown and Sandow Coal Plants, with 2.4 GW name-plate capacity combined, were announced to be closed, but the closure is still under reliability review by ERCOT (Koenig and Sorg, 2017). If the ERCOT permits the closure, this will decrease the capacity from coal-fired plants with once-through cooling and recirculating cooling by 1.2 GW and 1.3 GW. This may further diminish overall CO_2 emissions and water use.

Table 3
Major parameters and assumptions for ERCOT in 2030.

Parameters	Values	Parameters	Values
Coal price[a]	\$2.49/MMBtu	CO_2 transport cost[c]	\$3/short ton
Natural gas price[a]	\$4.93/MMBtu	CO_2 storage cost[c]	\$7/short ton
Nuclear fuel price	\$1.01/MMBtu	Economic book life time	20 yrs, wind; 30 yrs for others
Cum. load growth relative to 2012[b]	17.4%	Renewable set-asides[d]	7.8 M short tons CO_2
CO_2 allowance price[b]	\$13/short ton	Renewable set-asides incentive[d]	\$17.6/MWh
CO_2 mass-based + new source goal[b]	160 M short tons	Set-aside allocation, wind/solar[e]	54%, 46%
CO_2 emission limit for new PC	1400 lbs CO_2/MWh-g	Output-based set-aside	15.8 M short tons CO_2
CO_2 emission limit for new NGCC	1000 lbs CO_2/MWh-g	Reserve margin[f]	16.1%
		Weighted avg. cost of capital	7.0%

[a] Fuel prices were derived from EIA's fuel databases and projections (U.S. EIA, 2012, 2013a, 2015b).
[b] Demand growth, CO_2 allowance price, mass-based goal, new source complement, renewable set-asides, and output-based set-aside in terms of estimates using EPA's approach in CPP TSD (U.S. EPA, 2015c; d, f, g).
[c] CO_2 transport and storage costs based on Zhai et al. (2015).
[d] Renewable set-asides incentive rate based on the estimated difference in plant LCOE between new NGCC and wind power generation (see Appendix E).
[e] Set-aside allocation ratios for wind, solar based on ratio of wind and solar electricity generation in 2030 estimated by EPA using Integrated Planning Model (IPM) v5.15.
[f] Reserve margin is from ERCOT's report (ECCO International, 2013).

Table 4
Estimated electricity capacity and generation mix by fuel type, 2030.

Fuel type	Capacity mix (%)					Generation mix (%)				
	2012[a]	BAU	CPS	CPS+R	CPS+RW	2012[a]	BAU	CPS	CPS+R	CPS+RW
Nuclear	5.6	5.2	4.8	4.8	4.8	12.1	10.3	10.3	10.3	10.3
Coal	22.8	19.1	9.7	9.7	9.3	31.1	41.3	15.7	15.7	15.9
Gas	41.1	47.6	49.6	49.6	49.2	45.0	37.8	56.7	56.7	55.6
OG	17.5	16.2	15.1	15.1	15.0	0.4	0.9	1.0	1.0	1.0
Wind	12.2	11.3	14.6	14.6	14.9	11.1	9.5	13.1	13.1	13.5
Solar	0.1	0.1	5.6	5.6	6.3	0.0	0.0	3.1	3.1	3.5
Hydro	0.6	0.6	0.6	0.6	0.6	0.2	0.1	0.1	0.1	0.1

[a] Electricity generation, CO_2 emission, water use in 2012 estimated using model with fuel cost in 2012 dollars: \$2.16/MMBtu for coal; \$3.00/MMBtu for natural gas, \$3.06/MMBtu for OG, \$0.288/MMBtu for nuclear power (U.S. EIA, 2012, 2013a). More accurate estimates should be based on the unit commitment and economic dispatch model.

Table 5
Comparisons of cost, capacity, generation, CO_2 emissions and water use.

Model results	2012[a]	2030			
		BAU	CPS	CPS+R	CPS+RW
Total annual cost (\$ bn)	9.8	14.8	15.8	15.8	15.9
Total capacity (GW)	92.0	99.0	106.0	106.0	107.0
Total power generated (M MWh)	318.0	373.0	373.0	373.0	373.0
CO_2 emissions (M short tons)	180.0	240.0	160.0	160.0	160.0
Water withdrawal (bn gals)[b]	3010.0	3771.0	3025.0	3025.0	1916.0
coal	1733.0	2473.0	1658.0	1658.0	844.0
natural gas	324.0	277.0	335.0	335.0	91.0
oil and gas	48.0	116.0	127.0	127.0	77.0
nuclear	903.0	903.0	903.0	903.0	903.0
Water consumption (bn gals)	85.0	105.0	73.0	73.0	90.0
coal	32.0	55.0	8.0	8.0	22.0
natural gas	30.0	30.0	45.0	45.0	46.0
oil and gas	0.0	1.0	1.0	1.0	2.0
nuclear	18.0	18.0	18.0	18.0	18.0

[a] Electricity generation, CO_2 emissions, and water use in 2012 estimated using these fuel-related cost assumptions: \$2.16/MMBtu for coal; \$3.00/MMBtu for natural gas; and \$0.28/MMBtu for nuclear power (U.S. EIA, 2012, 2013a).
[b] Water withdrawal for hydroelectric power of 2 bn gals, all scenarios excluded.

6. Sensitivity analysis

To understand future pathways for environmentally-conscious power production, one must understand how CO_2 emissions regulations and other key factors affect the fundamental aspect of regional sustainability on water resources at the expected levels of electricity demand. Sensitivity analysis evaluates changes in the power generation profile and water use as a single parameter is varied.

6.1. Price sensitivity

Gas and coal prices, and CO_2 allowance and sale prices affect the generation mix estimates and, in turn, the water use estimates. Next discussed is the sensitivity of the results to these prices.

6.1.1. Natural gas and coal prices

The electricity generation mix is sensitive to coal and natural gas prices. The Henry Hub Natural Gas spot price was projected to have an annual market growth from 0.6% to 4.38% after 2012 (U.S. EIA, 2015a). After applying this growth rate to Texas' natural gas price in 2012, the natural gas price is estimated to range from \$3.34 per MMBtu to \$6.49 per MMBtu. Likewise, the coal price in 2030 is projected by EPA for the ERCOT region to range from \$2.1 to \$3.2 per MMBtu (in 2011 dollars) (U.S. EPA, 2015h). Fig. 5 shows the total water use by

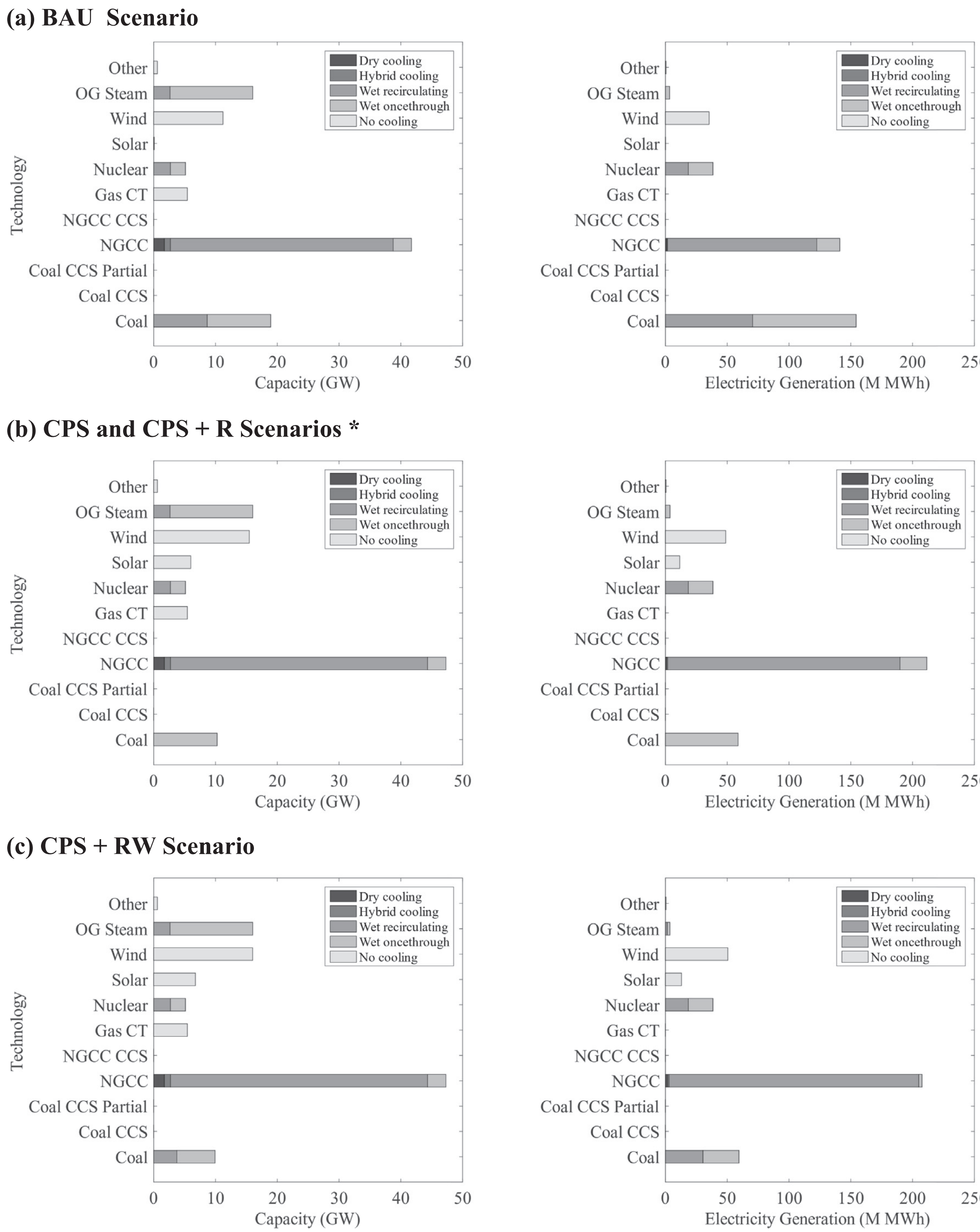


Fig. 4. Projections of electricity capacity and generation under the BAU, CPS, CPS + R, and CPS + RW Scenarios. *The projection of electricity capacity and generation under the CPS scenario is the same as the CPS + R scenario as no CCS retrofits are needed in the base CPS + R case without economic incentives.

scenario in response to changes in the natural gas price from \$3 to \$7 per MMBtu and the coal price from \$1 to \$4 per MMBtu, respectively.

Under the BAU scenario, generation from natural gas is estimated to increase by 108% with respect to the base case and to substitute for almost all coal-fired electricity generation when the natural gas price is at \$3 per MMBtu. Consequently, water withdrawal is estimated to decrease by 65%. Electricity generation from coal would reach the base case level (154 M MWh) when the natural gas price is \$5 per MMBtu or higher so withdrawal is estimated to be as high as 3770 bn gals (See Fig. 5a). It is the opposite when the coal price is \$3 per MMBtu or higher. (See Fig. 5c.) Also, total water consumption is estimated to be 20% lower when the natural gas price is \$4 per MMBtu or lower, and the same as the base case when the natural gas price is higher than this price. The opposite is observed when coal prices are higher than \$3 per MMBtu.

Under the CPS and CPS + R scenarios, water withdrawal shows an

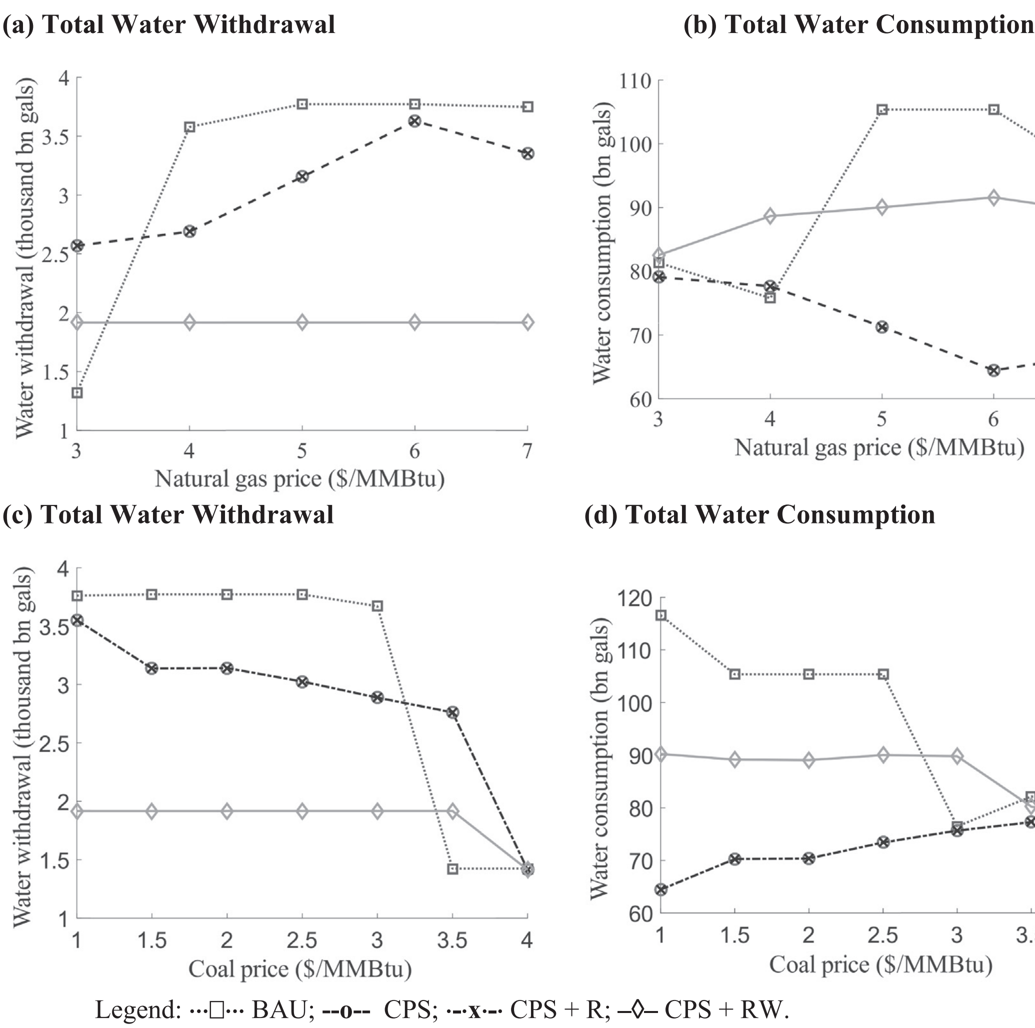


Fig. 5. Total water use by scenario as a function of fuel price. (a) Total water withdrawal. (b) Total water consumption. (c) Total water withdrawal. (d) Total water consumption.

increasing trend, but water consumption generally shows a decreasing trend with an increasing natural gas price. When the natural gas price is at $6 per MMBtu, water withdrawal is estimated to increase by 20% as generation from coal will increase by 70% above the base case.

There is also an increase in electricity generation from wind and solar by 144% at the $7 per MMBtu price level due to high electricity generation cost at NGCC plants and CO_2 emission constraints. But, water consumption may decrease by 14% when the generation from renewables becomes cheaper than from NGCC. In contrast, a low coal price does not result in an increase in electricity generation from coal due to the total CO_2 emissions constraint. A higher coal price at $4 per MMBtu will result in the retirement of all coal-fired EGUs and an increase from NGCC by 27% above the base case. These decrease water withdrawal to 1400 bn gals and water consumption to 82 bn gals. (See Figs. 5b and 5d.)

Under the CPS + RW scenario, water consumption decreases by 8% when the natural gas price reaches $3 per MMBtu because of less generation from coal-fired EGUs with recirculating cooling. When the coal price reaches $4 per MMBtu, however, water consumption decreases by 14% due to the retirement of all existing coal plants and more generation from renewables.

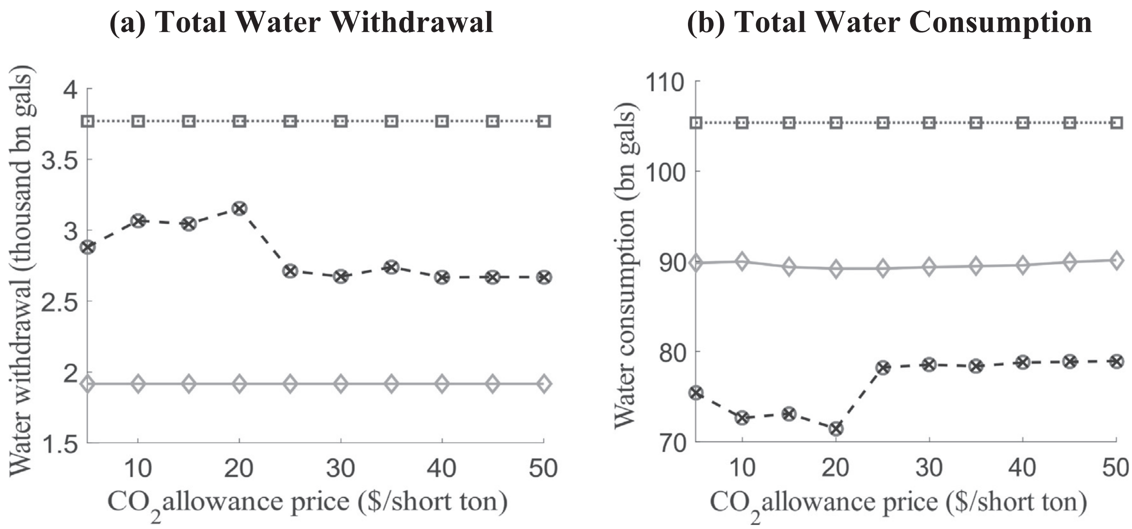
6.1.2. CO_2 allowance price

EPA recently estimated that for a 3.0% average discount rate, the average social cost of CO_2 will be $55 per short ton (2007 dollars) in 2030 (Interagency Working Group on Social Cost of Carbon, 2013). So, a sensitivity analysis was performed for the CO_2 allowance price ranging from $5 to $50 per short ton to examine how it would influence the electricity generation mix and water use.

Under the CPS and CPS + R scenarios, the electricity generation from renewable increases with an increasing allowance price, whereas electricity generation from new NGCC plants decreases to 33 M MWh when the allowance price is at $50 per short ton. Fig. 6 shows the total water use by scenario as a function of CO_2 allowance price. At the allowance price of $25 per short ton, the generation from coal-fired units with once-through cooling is 18% below the base case so that water withdrawal decreases to 2700 bn gals. In contrast, water consumption is estimated to increase by 7% above the base case because of more generation from existing coal-fired units with recirculating cooling. The water use under the CPS + RW scenario is not sensitive to the allowance price, mainly because the water withdrawal constraint restricts the electricity generation from existing coal and NGCC units with once-through cooling.

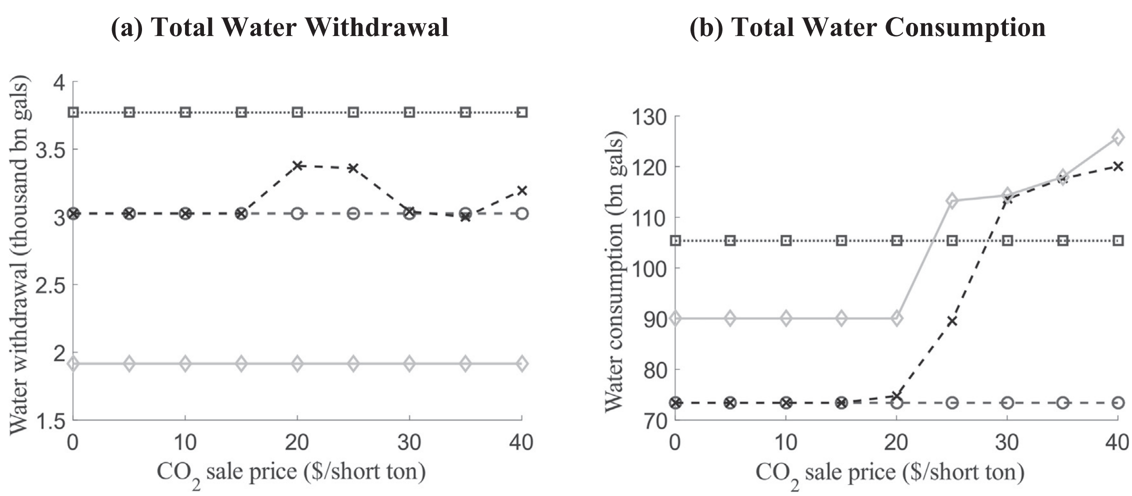
6.1.3. CO_2 sale price for enhanced oil recovery

Selling the captured CO_2 for use with EOR operations can bring an income stream in lieu of a CO_2 storage cost (IEA, 2015; Zhai et al., 2015). Depending on the oil price, this income stream provides an economic incentive for CCS deployment to control carbon pollution from fossil fuel-fired plants so more capacity and generation may be



Legend: ···□··· BAU; **--o--** CPS; ·--x·-- CPS + R; –◊– CPS + RW.

Fig. 6. Total water use by scenario as a function of CO_2 allowance price. (a) Total water withdrawal. (b) Total water consumption.



Legend: ···□··· BAU; **--o--** CPS; ·--x·-- CPS + R; –◊– CPS + RW

Fig. 7. Total water use by scenario as a function of CO_2 sale price. (a) Total water withdrawal. (b) Total water consumption.

yielded by coal-fired and NGCC plants with CCS. Fig. 7 shows the total water use by scenario as a function of CO_2 sale price.

Under the CPS + R scenario, when the CO_2 sale price is higher than \$15 per short ton, about 7–49% of existing NGCC units (in terms of the capacity) are retrofitted with CCS instead of coal-fired units because of cheap natural gas price plus lower cost of electricity generation than that of coal EGUs retrofitted EGUs.[12] Electricity generation from these units reaches 120 M MWh at the sale price of \$40 per short ton, representing 32% of the total fleet generation. Consequently, water consumption is estimated to increase by 64% above the base case, but water withdrawal is estimated to increase only by 6% due to more generation from existing coal units with once-through cooling. For the CPS + R scenario, there is a variation of about 10% or less in water withdrawal when the CO_2 sale price is higher than \$15 per short ton, mainly because increased CCS retrofits elevate parasitic loads and lead to variations in the generation mix under a number of the constraints discussed above, especially the generation from existing coal-fired plants with once-through cooling.

Even with the sale price of \$40 per short ton of CO_2, the total water withdrawal is lower under the CPS scenario and the CPS + R scenario than under the BAU scenario. However, the total water consumption in the CPS + R and CPS + RW scenarios is higher than under the BAU scenario when the sale price is higher than \$20 per short ton because of additional water consumption from CCS retrofits at the plants that use recirculating cooling systems.

6.2. *Electricity demand*

For a given emissions target in 2030, the demand for electricity can affect the low-carbon energy roadmap and water use for electricity generation. Corporate and individual consumers may reduce their electricity demand by employing various energy efficiency measures and on-site renewable energy technologies. Conversely, electricity demand may be higher than expected due to high economic growth, widespread adoption of electric vehicles, and the large industrial loads of the future. ERCOT (2015c) also has estimated that there could be a

[12] When the CO_2 sale price is higher than \$15 per short ton, electricity generation from coal with once-through cooling will reach 75 M MWh, but it will decrease again to 66 M MWh at \$30 per short ton when generation from NGCC with CCS retrofit reaches 26% of the total fleet generation.

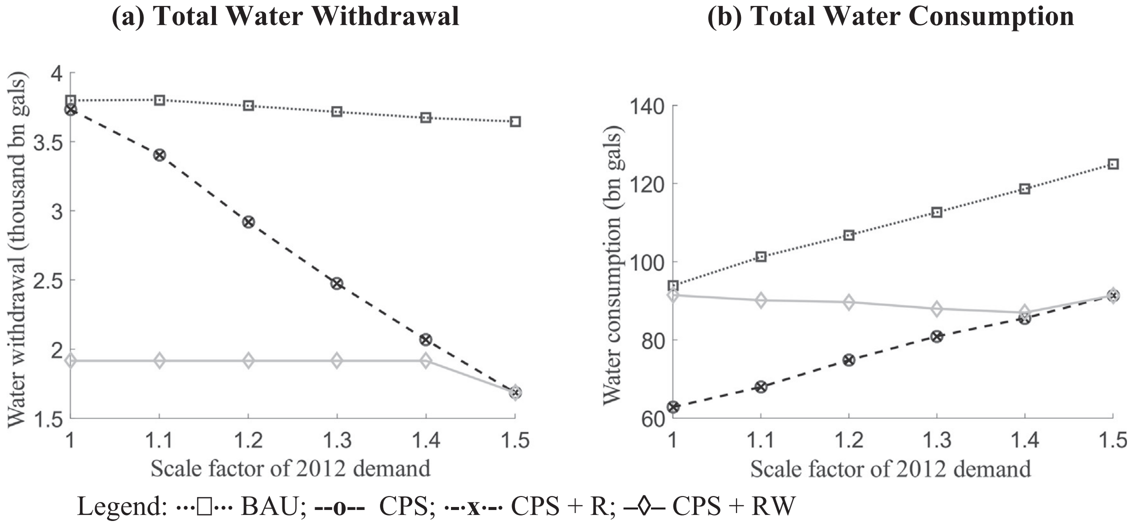


Fig. 8. Total Water Use by Scenario as a Function of Scale Factor of Demand in 2012. (a) Total water withdrawal. (b) Total water consumption.

10% difference in their forecasts based on the historical volatility of the weather. This prompted additional sensitivity analysis on the demand with a scale factor varying from 1.0 to 1.5 of 2012 demand level.[13] Fig. 8 shows the total water use by scenario at different levels of electricity demand.

Under the BAU scenario, as electricity demand increases, generation from new NGCC EGUs with recirculating cooling increases gradually to 40% of fleet generation at the scale factor of 1.5. However, there is a decrease in generation from existing NGCC EGUs with once-through cooling (by 53% of base case level). As a result, the water withdrawal under the BAU scenario decreases slightly with the demand increase. In contrast, the low-carbon scenarios have less water withdrawal because of decreased electricity generation from existing coal-fired and NGCC EGUs with once-through cooling under the given emission constraint. On the other hand, the total water consumption increases as electricity demand increases because of the increased penetration of recirculating cooling under all the scenarios except for the CPS + RW scenario, which is illustrated later.

Under the CPS and CPS + R scenarios, water withdrawal has a decreasing trend, but total water consumption increases. This is because of increasing generation from new NGCC plants with recirculating cooling coupled with decreasing generation from existing coal plants with once-through cooling as the level of electricity demand increases. The total water withdrawal is estimated to be about 23% higher than the base case at the scale factor of 1 (no increase in electricity demand from 2012 level) because the increase in generation from new renewables incentivized by set-asides allows an increase in the electricity generation from existing coal with once-through cooling by 52% above the base-case level. When the electricity demand in 2030 is 50% more than the 2012 level (corresponding to the scale factor of 1.5), two times more generation from NGCCs with recirculating cooling is required to comply with the emission limit. This results in a decrease by 44% in the water withdrawal and an increase by 24% in the water consumption.

Under the CPS + RW scenario, as demand increases, water withdrawal will stay under the water limit, but water consumption will decrease slightly. This is due to a decrease of generation from existing coal-fired EGUs with recirculating cooling to zero at the scale factor of 1.4 under the fixed emission constraint.

6.3. Water withdrawal availability

The availability level of water withdrawal affects the cooling technology penetration profile. So, we performed an additional sensitivity analysis on the CPS + RW scenario with water withdrawal availability ranging from 75% to 25%. The results demonstrate minor changes in the capacity and generation mix profiles (see Table 6), but a significant increase in water consumption of coal-fired EGUs (see Table 7) as the water availability constraint becomes stricter. This is because of an increase in generation from coal-fired EGUs with recirculating cooling as more EGUs with once-through cooling retire. A very low level of water availability (e.g. 25% of these reference level) can even push the retirement of almost all existing coal-fired EGUs with once-through cooling.

7. Discussion

In February 2016, the implementation of the CPP was halted due by the U.S. Supreme Court (2016), which granted a stay order until related legal issues were resolved. Then in early 2017, a presidential order put the carbon pollution standards under a review, resulting in the proposed repeal of the CPP (The White House, 2017). Now it is up to the individual states whether to implement these regulations for reducing the CO_2 emissions from the electric power sector or to continue the status quo. The scenario analysis results show the consequences of the pathways that may be selected by a representative state.

If the regulations are not implemented, the state's electricity generation will depend on the fuel costs, particularly natural gas prices. For ERCOT in Texas, when the cost of generating electricity from coal is much cheaper than from natural gas, coal-fired EGUs may supply 52% of its power fleet's generation mix. Consequently, the fleet's total CO_2 emissions will be 43% higher than in 2012. ERCOT should also be prepared for a large increase in total water use for electricity generation because of intensive water use for coal-fired EGUs.[14]

Otherwise, generation from natural gas under the BAU scenario may reach 79% of the fleet's generation mix when the average gas price is \$3/MMBtu. Hence, total CO_2 emissions will be 130 M short tons, or 28% lower than in 2012. This is lower than the CO_2 emission cap for ERCOT under CPP. So even with the status quo, ERCOT may achieve

[13] A scale factor of 1 is about 15% lower than the base case level, and a scale factor of 1.5 is about 28% higher than the base case level. These cover a +/-10% difference from the base case level based on the historical volatility of the weather (ERCOT, 2015c). These also may cover the increase of demand for high forecasted economic growth of 1.5% annual growth in the West South Central Region (U.S. EIA, 2015a). This is about 1.3 times the 2012 demand level.

[14] Our scenario analysis for Texas has not considered the Texas' Regional Haze Plan that regulates the emissions of sulfur dioxide (SO_2) from coal plants.

Table 6
Estimated electricity capacity and generation mix by fuel type, CPS + RW, 2030.

Fuel type	Capacity mix (%)			Generation mix (%)		
	CPS + RW 75%	CPS + RW 50%	CPS + RW 25%	CPS + RW 75%	CPS + RW 50%	CPS + RW 25%
Nuclear	4.8	4.8	4.5	10.3	10.3	9.7
Coal	9.7	9.3	7.5	15.6	15.9	17.5
Gas	49.6	49.2	49.3	56.8	56.6	53.2
OG	15.1	15.0	14.7	1.0	1.0	0.6
Wind	14.6	14.9	15.7	13.1	13.5	14.5
Solar	5.6	6.3	7.8	3.1	3.5	4.4
Hydro	0.6	0.6	0.5	0.1	0.1	0.1

Notes. This table compares the capacity and generation mix profiles under the CPS + RW scenario when the amount of water withdrawal available for the electric power sector ranges from 75% to 25% of the reference level, Texas' annual freshwater withdrawal in 2010.

Table 7
Estimated water consumption by fuel type, CPS + RW, 2030.

	CPS + RW 75%	CPS + RW 50%	CPS + RW 25%
Total water consumption (bn gals)	75	90	103
coal	8	22	39
natural gas	46	46	43
oil and gas	1	2	1
nuclear	18	18	17

Notes. This table compares the water consumption under the CPS + RW scenario when the amount of water withdrawal available for the electric power sector ranges from 75% to 25% of the reference level.

the CO_2 emission level recommended by the U.S. EPA, if the natural gas price is low (< \$4 per MMBtu), or if the coal price is very high (> \$3 per MMBtu). Additionally, the resulting water withdrawal and consumption in 2030 will be 53% and 3% lower than in 2012, respectively. Over time, U.S. electricity generation from coal has been declining due to low natural gas prices in massive production from shale. If the trend of decreasing prices persists, U.S. power utilities will retire more coal-fired plants in the coming years.[15]

If ERCOT selects a scenario with carbon pollution regulations, CO_2 emissions will be guaranteed to be lower. With constraints on coal-fired generation, ERCOT will need to add new NGCC and renewable EGUs to meet the load demand. Water withdrawal will be lower than in the status quo pathway of business-as-usual. More reductions in water use will benefit from cheap natural gas prices and high CO_2 allowance prices because the two factors encourage more electricity generation from NGCC plants and renewables, respectively.

CCS could be retrofitted as a mitigation measure to help meet the carbon regulations. However, economic incentives for CCS do matter with respect to its viability in competition with renewable and gas-fired plants to achieve the moderate reduction target outlined by the CPP. The income from selling the captured CO_2 with a price of more than \$15 per short ton would economically facilitate CCS deployment. However, cheap natural gas prices incentivize the implementation of CCS at existing NGCC plants instead of existing coal-fired EGUs. As generation from EGUs retrofitted with CCS increases, the fleet water consumption will increase.

Water withdrawal is remarkably affected by changes in electricity generation from plants with once-through cooling systems. When a significant constraint on water withdrawal happens, the power fleet will have more generation from recirculating-cooled than once-through cooled EGUs. More generation from renewable and NGCC plants with recirculating cooling will decrease water withdrawal but slightly increase water consumption.

Once-through cooling is not considered for all new plants because of regulations on cooling water intake structures under Section 316(b) of the Clean Water Act. As such, the total water withdrawal of all low-carbon scenarios in 2030 will be similar to or less than the 2012 level. An increase in regional load demand under the fixed emission constraint can elevate water consumption instead of water withdrawal because of increased share of renewables and NGCC plants with recirculating cooling in the future grid. Dry and hybrid cooling systems can significantly reduce consumptive water use. However, their larger parasitic load and capital cost impede widespread deployment in competition with recirculating cooling in the future fleet.

8. Conclusion

This study explores different electric power generation pathways with or without carbon regulations and highlights the benefits of the transition to a low-carbon electricity grid in reducing both CO_2 emissions and water use and their dependence on a variety of factors or incentive mechanisms. The moderate levels of CO_2 emission reductions will promote electricity generation from NGCC and renewables plants and reinforce the retirement of a number of existing coal-fired EGUs.

In the absence of carbon regulations, cheap natural gas prices have been promoting a shift away from coal for electricity generation, resulting in recent reductions in CO_2 emissions. Cost reductions with renewables also spurred the shift. However, such market-driven emission reductions hardly exceed the goals that had been set under the carbon regulations. High natural gas prices even may reverse the emission trajectory in the future. Unlike the volatile market forces, the carbon rules can provide low-carbon technologies with technical and economic mechanisms that facilitate their stable development or preparation for the deep emission reductions required for global climate change mitigation.

For either the BAU or low-carbon scenarios, both coal- and natural gas-fired plants will still be the major suppliers in the U.S. electricity grid, at least in the near future. NGCC plants will dominate the electric power fleet under the moderate carbon constraints. However, direct control of CO_2 emissions from NGCC plants is also needed for deep reductions in an aim to hold the increase in the global average temperature at or below 2 °C this century. CCS is a key technology for significantly reducing CO_2 emissions from both coal- and gas-fired power plants. Given today's high cost, however, CCS is unlikely to be competitive with NGCC and renewable plants in complying with moderate emission limits. So, economic incentives are needed to promote CCS deployment for the long-term benefit of stabilizing global climate change.

Several caveats are in order. The scenario modeling did not include

[15] In 2017, the U.S. Secretary of Energy issued a Notice of Proposed Rulemaking (NOPR) directing the Federal Energy Regulatory Commission (FERC) to ensure that "certain reliability and resilience attributes of electric generation resources" (i.e., electricity generation from coal and nuclear as base load) are fully valued. FERC has no jurisdiction over ERCOT's grid though. So, this ruling will not affect ERCOT's power system.

unit-level operating constraints and power transmission and distribution constraints or expansion. At the unit level, existing EGUs retrofitted with CCS for 90% CO_2 capture can achieve more emission reductions than the required amount while complying with the emission limits. However, the analysis did not include the potential trading mechanism for emission reduction credits (ERC) for CCS retrofits (Talati et al., 2016). A combination of ERC trading and CO_2-EOR can provide a stronger economic incentive for CCS deployment. In addition to heat rate improvement, the analysis did not consider other measures of CO_2 mitigation from existing coal EGUs, such as boiler upgrades and gas- or biomass-coal co-firing. Also, the CPS + RW scenario did not take into account the seasonal variability in water availability, which goes beyond the scope of this study.

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Appendix A. Mass-based CO_2 allowance allocations

See Table A1 here.

Table A1
CO_2 Allowance allocations for ERCOT's affected existing generating technologies.

Existing technologies	CO_2 Allowances (M short tons)	Existing technologies	CO_2 Allowances (M short tons)
Coal once-through	38.76	NGCC once-through	4.83
Coal recirc	25.73	NGCC recirc	55.66
OG steam once-through	3.97	NGCC hybrid	1.31
OG steam recirc	0.64	NGCC dry	2.00

Notes. CO_2 allowances from Allowance Allocation Proposed Rule TSD (U.S. EPA, 2015g), for affected existing plants in ERCOT's region are listed by technology type and cooling system.

Appendix B. Cost and performance metrics for electric power plant technologies

See Tables B1–B3 here.

Table B1
New plants: cost and performance metrics.

Technology	Var O&M ($/MWh)	Fixed O&M ($/kWyr)	Capital cost ($/kW)	Heat rate (MMBtu/MWh)	Plant size (MW)	CO_2 emission rate (Short Ton/MMBtu)	Water withdrawal rate (Gal/MMBtu)	Water consumption rate (Gal/MMBtu)	ELCC
Nuclear recirc	2.14	93.28	5530	10.4	1117	0.000	105.9	64.6	0.96
Nuclear hybrid	2.14	93.28	5761	10.4	1117	0.000	60.5	36.9	0.96
Nuclear dry	2.14	93.28	6020	10.4	1117	0.000	15.1	9.2	0.96
Coal recirc	5.61	66.02	2252	8.7	550	0.102	67.0	56.8	0.93
Coal hybrid	4.44	69.02	2521	9.0	550	0.103	38.3	32.4	0.93
Coal dry	4.63	68.32	2374	9.0	550	0.103	9.5	8.1	0.93
Coal CCS recirc	9.71	107.63	3972	12.0	550	0.010	91.5	70.5	0.93
Coal CCS hybrid	13.75	110.38	4257	12.3	550	0.010	75.5	58.2	0.93
Coal CCS dry	12.55	108.41	3994	12.3	550	0.010	59.5	45.8	0.93
IGCC	8.25	89.66	2787	8.5	622	0.099	49.9	44.8	0.93
IGCC CCS	10.79	122.36	3970	10.8	517	0.010	61.3	50.9	0.93
NGCC recirc	3.27	15.37	1023	6.4	400	0.059	38.0	31.9	1.00
NGCC hybrid	3.27	15.37	1115	6.4	400	0.059	19.4	16.3	1.00
NGCC dry	3.27	15.37	1235	6.4	400	0.059	0.9	0.3	1.00
Gas CT	10.37	7.04	676	9.8	210	0.059	0.0	0.0	0.95

(*continued on next page*)

Table B1 (*continued*)

Technology	Var O&M ($/MWh)	Fixed O&M ($/kWyr)	Capital cost ($/kW)	Heat rate (MMBtu/ MWh)	Plant size (MW)	CO_2 emission rate (Short Ton/ MMBtu)	Water withdrawal rate (Gal/MMBtu)	Water consump-tion rate (Gal/ MMBtu)	ELCC
Wind	0.00	46.50	1665	1.0	100	0.000	0.0	0.0	0.24
Solar PV	0.00	7.37	1292	1.0	20	0.000	0.0	0.0	0.25
Coal CCS 20% recirc	6.31	77.18	2668	9.5	550	0.082	79.1	66.5	0.93
Coal CCS 20% hybrid	7.44	80.25	2930	9.7	550	0.083	45.2	38.0	0.93
Coal CCS 20% dry	6.46	78.82	2749	9.7	550	0.083	11.3	9.5	0.93

Notes. Costs, heat rates, plant sizes, and CO_2 emission rates are from: U.S. EIA (2013b) for nuclear, gas CT, wind, and solar PV; and NETL (2013) for coal, IGCC, and NGCC with/without CCS. Water withdrawal and consumption rates of nuclear, PC, and NGCC plants with once-through and recirculating cooling, and NGCC plants with dry cooling are adopted from Macknick et al. (2012a); for others, the rates were estimated using correction factors on water withdrawal rates in Webster et al. (2013). The ELCCs for nuclear, coal, IGCC, NGCC, and gas CT are from Webster et al. (2013) too; the ELCC of wind was adopted from ECCO International (2013); and ELCC of solar was based on U.S. EPA (2015h). The capital cost and water withdrawal rate for generation technologies with hybrid and dry cooling were calculated for the relevant correction factors using IECM (2015). The same is true for fixed and variable O&M costs for coal, OG steam, and NGCC with hybrid and dry cooling.

Table B2
Existing plants: cost and performance metrics.

Technology	Var O&M ($/MWh)	Fixed O&M ($/kWyr)	Heat rate (MMBtu/MWh)	Plant size (MW)	CO_2 emission rate (Short tons/MBtu)	Water withdraw rate (Gals /MMBtu)	Water consumption rate (Gals /MMBtu)	ELCC
Coal once-through	4.48	61.56	11.1	550	0.100	2600.4	11.9	0.93
Coal recirc	5.73	66.02	11.2	550	0.100	67.0	56.8	0.93
OG steam once-through	0.62	3.16	12.0	210	0.058	0.0	15.2	1.00
OG steam recirc	0.80	3.33	12.2	210	0.058	0.0	15.2	1.00
NGCC once-through	0.00	13.54	7.8	400	0.061	1674.0	15.2	1.00
NGCC recirc	3.27	15.37	7.8	400	0.061	38.0	31.9	1.00
NGCC hybrid	3.20	17.05	7.8	400	0.061	19.4	16.3	1.00
NGCC dry	3.21	16.83	7.8	400	0.061	0.0	0.0	1.00
Wind	0.00	39.55	1.0	100	0.000	0.0	0.0	0.24
Solar PV	0.00	27.75	1.0	20	0.000	0.0	0.0	0.60
Nuclear once-through	2.14	93.28	10.4	1117	0.000	4264.4	25.9	0.96
Nuclear recirc	2.14	93.28	10.4	1117	0.000	105.9	64.6	0.96
Gas CT	10.37	7.04	12.6	210	0.063	0.0	0.0	0.95
Hydroelectric	0.00	14.13	1.0	500	0.000	4491.0	4491.0	0.96

Notes. Sources: U.S. EIA (2013a), NETL (2013), Webster et al. (2013), Macknick et al. (2012a). water withdrawal rates for plants with hybrid and dry cooling are calculated using correction factors, as discussed earlier. Variable and fixed O&M costs for coal, OG steam, and NGCC with hybrid and dry cooling were adjusted using correction factors calculated from IECM estimates. OG steam costs are based on average costs used in IPM v.5.15; and the CO_2 emission and heat rates were calculated based on their average rates at existing plants in the ERCOT region in 2012. Under scenarios that implement CPP, a 2.3% heat rate improvement for existing coal-fired EGUs is applied. So, their average heat rate in ERCOT is expected to decrease from 11.2 MMBtu per MWh to 10.9 MMBtu per MWh, with a retrofit cost of $100 per kW (U.S. EPA, 2014). Water use in hydroelectric is unique because a huge amount of water flows to spin the turbines so the water withdrawal of hydroelectric was assumed to be the same as its water consumption instead of the volume of water flow.

Table B3
Existing coal and NGCC with CCS retrofit: cost and performance metrics.

Technology	Var O&M ($/MWh)	Fixed O&M ($/kWyr)	CCS retrofit capital cost ($/kW)	Heat rate (MMBtu/ MWh)	Plant size (MW)	CO_2 emissions (Short tons/ MMBtu)	Water withdrawal rate (Gals/MMBtu)	Water consumption rate (Gals/MMBtu)	ELCC
Existing coal recirc + CCS	11.29	121.23	1409	13.8	468	0.010	93.9	72.2	0.93
Existing NGCC recirc + CCS	3.74	40.43	696	9.1	344	0.006	63.3	47.4	1.00
Existing NGCC hybrid + CCS	3.78	44.13	786	9.3	344	0.006	55.0	41.2	1.00
Existing NGCC dry + CCS	3.54	41.04	708	9.1	344	0.006	45.9	34.4	1.00

Notes. Capital costs of CCS retrofit, O&M costs, heat rates, and CO_2 rates are estimated using IECM; water withdrawal and consumption rates follow NETL's estimates (NETL, 2013); water withdrawal rate for plants with hybrid and dry cooling is calculated using the correction factors from IECM.

Appendix C. Cost and performance comparison by plant type, CCS, and cooling system using IECM

See Tables C1–C4 here.

Table C1
New PC plants with and without CCS.

Super critical pulverized coal	CO_2 emissions (Short tons/MMBtu)	Water withdrawal (Short tons/yr)	Water consumption (Short tons/h)	Capital cost ($/kW-Net)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	Plant heat rate (MMBtu/MWh)
With recirc cooling (base)	0.101	10,300,000	7,200,000	2031	66.64	2.77	8.9
With dry cooling	0.101	2,100,000	1,100,000	2141	68.97	2.29	9.3
With hybrid cooling	0.101	–	–	2273	69.68	2.20	9.3
CCS 20% with recirc cooling	0.081	12,200,000	8,500,000	2374	79.56	79.56	9.8
CCS 20% with dry cooling	0.081	4,100,000	2,400,000	2479	79.56	79.56	10.0
CCS, recirc cooling (base)	0.010	–	–	3544	105.13	9.94	12.4
CCS, dry cooling	0.010	–	–	3563	105.89	12.85	12.7
CCS, hybrid cooling	0.010	–	–	3798	107.82	14.08	12.7

Notes. The costs and rates were calculated using IECM. A new PC plant is specified as a typical new supercritical pulverized coal plant with traditional air pollution controls. The ambient air temperature was set to the average temperature in Texas from 1901 to 2015 (NOAA, 2015). The bypass design for partial CO_2 capture and Amine System FG+, a popular approach for CO_2 capture, were selected if the plant had a CCS system. The cooling system used was wet or dry. The applicable correction factor is the ratio of the costs or rates of coal with 20% CO_2 capture and without CO_2 capture. Variable O&M costs were calculated without the fuel costs included also.

Table C2
New NGCC plants with and without CCS.

New NGCC	Capital cost ($/kW-Net)	Fixed O&M ($M/yr)	Variable O&M ($M/yr)	Net electrical output (MW)	Heat rate (MMBtu/MWh)
With recirc cooling (base)	772	10.40	196.2	207	6.82
With hybrid cooling	933	11.20	192.0	206	6.92
With dry cooling	824	11.10	192.8	209	6.92
CCS, recirc cooling	1397	18.21	206.9	207	7.88
CCS, hybrid cooling	1578	19.22	208.8	206	8.05
CCS, dry cooling	1472	18.74	209.2	209	8.05

Notes. The costs and rates were calculated using IECM. For plants with hybrid cooling, they were estimated based on a comparative study by Zhai and Rubin (2016). A new NGCC plant was specified as a typical new plant with two GE 7FB gas turbines, and a 75% load capacity factor; natural gas cost was assumed to be $7.476/mscf; and ambient air temperature, CCS and cooling systems were the same as in the specification of a new PC plant in Texas.

Table C3
Existing PC plants.

Subcritical pulverized coal	CCS retrofit cost ($/kW-Net)	Fixed O&M ($/kW)	Variable O&M ($/MWh)	Electrical output (MW)	Heat rate (MMBtu /MWh)
With recirc cooling (base)	0	60.95	2.33	550	9.4
With once-through cooling	0	64.21	2.98	550	9.5
+CCS with recirc cooling	1409	121.23	11.29	468	13.8

Notes. Costs and rates for coal wet-once-through and coal wet-recirculating were calculated using IECM. Existing PC plants were specified as fully-amortized subcritical pulverized coal plants. The coal type, capacity factor, ambient air temperature, CCS system, and cooling system were specified as in IECM for a new PC plant. Variable O&M cost does not include the fuel cost component. A retrofit factor of 1.25 for CCS retrofit costs is applied for integrating CCS systems into plants.

Table C4
Existing NGCC plants.

Existing NGCC	CCS retrofit cost ($/kW-Net)	Fixed O&M ($M/yr)	Variable O&M ($M/yr)	Electrical output (MW)	Heat rate (MMBtu/MWh)
With recirc cooling (base)	0	10.0	189.4	558	7.08
With once-through cooling	0	8.9	188.3	562	7.00
With dry cooling	0	10.6	186.1	543	7.16
+CCS, recirc cooling	696	19.4	200.1	479	8.20
+CCS, dry cooling	708	19.4	197.1	473	8.22

Notes. The costs and rates were calculated using IECM using the specification listed above. An existing NGCC plant was specified as a fully amortized NGCC plant with two GE 7FA gas turbines, and a 75% load capacity factor; natural gas cost, ambient air temperature, CCS and cooling systems were the same as in the specification of a new NGCC plant in Texas. As in existing PC plants, a retrofit factor of 1.25 for CCS retrofit costs is applied to integrating CCS systems into plants.

Appendix D. Correction factors by power generation technology

See Tables D1 here.

Table D1
Costs and water use correction factors.

Technology	Var O&M ($/MWh)	Fixed O&M ($/kWYr)	Capital cost ($/kW)	Heat rate (MMBtu /MWh)	Water withdrawal rate (Gals /MMBtu)	Water consumption rate (Gals /MMBtu)
Nuclear recirc	1.00	1.00	1.00	1.00	1.00	1.00
Nuclear hybrid	1.00	1.00	1.04	1.00	0.57	0.57
Nuclear dry	1.00	1.00	1.09	1.00	0.14	0.14
Coal recirc	1.00	1.00	1.00	1.00	1.00	1.00
Coal hybrid	0.79	1.05	1.12	1.04	0.57	0.57
Coal dry	0.83	1.03	1.05	1.04	0.14	0.14
Coal CCS recirc	1.00	1.00	1.00	1.00	1.00	1.00
Coal CCS hybrid	1.42	1.03	1.07	1.02	0.83	0.83
Coal CCS dry	1.29	1.01	1.01	1.02	0.65	0.65
Coal CCS 20% wet-recirc	1.28	1.17	1.18	1.10	1.18	1.17
Coal CCS 20% hybrid	1.11	1.04	1.10	1.02	0.67	0.67
Coal CCS 20% dry	1.01	1.02	1.03	1.02	0.34	0.29
NGCC recirc	1.00	1.00	1.00	1.00	1.00	1.00
NGCC hybrid	0.98	1.01	1.21	1.11	0.51	0.51
Existing coal recirc	1.00	1.00	–	1.00	1.00	1.00
Existing coal once-through	0.78	0.95	–	0.99	–	–
Existing NGCC recirc	1.00	1.00	–	1.00	1.00	1.00
Existing NGCC once-through	0.99	0.88	–	0.99	–	–
Existing NGCC hybrid	0.98	1.01	1.21	1.11	0.51	0.51

Notes. The factors for variable O&M, fixed O&M, capital costs, and heat rate were calculated using results estimated in IECM. The factors for water withdrawal and consumption rates were calculated using the water withdrawal rates estimated in Webster et al. (2013), except for the rates of Coal CCS 20% (using IECM). All technologies with wet cooling have a correction factor of 1, indicating the benchmark for calculating the correction factors of the corresponding technologies with wet once-through, hybrid, and dry cooling.

Appendix E. The power plant capacity expansion optimization model

This appendix provides details of an optimization model that was built to permit carbon pollution and water withdrawal outcomes to be analyzed in terms of the projected parameters for the ERCOT fleet power generation decision variables in an integer program that characterizes choices to be made under four pathway scenarios involving different generation and cooling technologies, CO_2 emission policies, and water withdrawal limitations. For the details of the modeling notation, see Table E1.

The objection function of the expansion model is:

$$\begin{aligned} \text{Min } NetCost &= f\,[TotCosts;\ TotOffsets] \\ &= f\,[TotInvestCost,\ TotVarCost,\ TotFixCost,\ TotFuelCost,\ TotCO_2TSCost,\ TotCO_2AllowCost; \\ &\quad TotCO_2CaptureOffset,\ TotCO_2AllowOffset,\ TotRenewSetAsideOffset] \end{aligned} \tag{1}$$

The decision variables in the model are $Number_i$, $Fraction_i$, Gen_{ij}, $CO_2AllowBuy_i$, $CO_2AllowSell_i$, and $CO_2AllowOutputBased_i$.

The total fleet investment cost is the sum of the capital costs of new EGUs, the retrofit costs for improving the heat rate of existing EGUs (if applicable), and the retrofit costs for adding a CCS system to coal and natural gas-fired EGUs (if applicable). These costs are annualized using a capital recovery factor:

$$\begin{aligned} TotInvestCost \;=\; & \textstyle\sum_{i\in\{New,RenewSetAside} [Number_i \times Capacity_i \times CapRecovFactor_i \times InvestCost_i] \\ & + \sum_{i\in Retro} [Number_i \times Capacity_i \times CapRecovFactor_i \times RetroCostCCS_i] \\ & + \textstyle\sum_{i\in Exist} [Fraction_i \times ExistNumber_i \times Capacity_i \times CapRecovFactor_i \times RetroCostHeat_i] \end{aligned} \tag{2}$$

where $CapRecovFactor_i \;=\; \dfrac{WACC}{1 - \frac{1}{(1+WACC)^{ServLife_i}}}$.

The weighted average cost of capital, WACC, is assumed at 7%, as in regulatory assessments. The economic service life for all generation technologies is 30 years, except for wind at 20 years (Webster et al., 2013). All existing EGUs are fully amortized. Total fixed O&M cost for new and

Table E1
Modeling notation in the integer programming formulation.

Notation	Definition	Comments
i, j	Subscripts: technology *i*; load strip *j* in a discretized load duration curve	$i \in I$ that includes sets of: 20 new, 2 new renewable with set aside, 14 existing, 4 and existing with CCS retrofit technologies; load duration curve discretize into 20 sequentially-ordered hourly-load strips; $j \in J = \{1, 2, \ldots, 438)$ with 1 = peak load strip
New, RenewSetAside, Retro, Exist	Sets of technologies: new, renewable with set-asides, existing with CCS retrofit, and existing technologies.	
$Number_i$	Number of EGUs from technology *i*	Decision variables for $i \in \{New, RenewSetAside, Retro\}$ but fixed values for $i \in Exist$
$ExistNumber_i$	Number of EGUs from existing technology *i*	Number of existing EGUs
$Fraction_i$	Fraction of remaining EGUs of technology *i*	Decision variables for $i \in Exist$
Gen_{ij}	Electricity generation (in MWh) of EGUs of technology *i* dispatched to meet the load demand in load strip *j*	Decision variables for electricity generation for technologies
$CO_2AllowBuy_i$, $CO_2AllowSell_i$, $CO_2AllowOutputBased_i$	CO_2 allowance (in short tons) of technology *i* purchased from the market; sold to the market; assigned to existing NGCC plants	Decision variables for CPP-affected existing technologies only: coal, OG steam, NGCC
$Capacity_i$	Plant nameplate capacity (MW) for an EGU of technology *i*	Intended full-load output of EGU; assumed equal for all EGUs of same technology
$CapRecovFactor_i$	Capital recovery factor (fraction/yr) of technology *i*	Factor for annualized capital cost
$RetroCostHeat_i$	Retrofit cost ($/kW) to decrease heat rate of technology *i*	Cost to improve energy efficiency of existing technology; only applicable for coal-fired technology in carbon-regulated scenarios; $100 per kW (EPA)
$RetroCostCCS_i$	CCS retrofit cost ($/kW) of technology *i*	Applied to existing coal-fired and NGCC EGUs only
$ServLife_i$	Economic service life (yrs) of technology *i*	30 years for all technologies, except for wind
$HeatRate_i$	Heat rate (MMBtu/MWh) of technology *i*	Energy input to a system divided by electricity generated
$CO_2CaptureRatio_i$	Percent CO_2 captured relative to the percent that is not, for technology *i*	Ratios are 9:1 for technologies with full CCS; and 1:4 for technologies with 20% capture
$Demand_j$	Demand (MWh) in load strip *j*	Demand is avg of hourly load in load strip $j \times 20$ (hourly load in-stances); 1st strip uses peak load
$ELCC_i$	Effective load carrying capacity % of technology *i*	Determines maximum load capacity of a plant's technology
$WaterWithRate_i$	Water withdrawal rate (Gals/MMBtu) of technology *i*	Amount of water a power plant takes in from the source (e.g., river, lake), some of which is returned, per energy produced
CO_2Allow_i	Allocated CO_2 allowance (short tons) of technology *i*	Allocation based on historical generation in 2012 for CPP-affected technologies only
$CO_2EmissionRate_i$	CO_2 emission rate (short tons/MMBtu) of technology *i*	Mass of CO_2 released per unit energy produced
$RenewIncentive_i$	Renewable incentive ($/MWh) of technology *i*	Assumed to be $17.6/MWh and applicable for new renewable with set-asides only
$InvestCost_i$, *TotInvestCost*	Capital investment cost ($/kWyr) of technology *i*; total capital investment cost ($)	Cost of building a power plant
$FixCost_i$, *TotFixCost*	Fixed O&M cost ($/kWyr) of technology *i*; total fixed O &M cost ($)	O&M: operation & maintenance
$VarCost_i$, *TotVarCost*	Variable cost O&M cost (in $/MWh) of technology *i*; total variable O&M cost ($)	Variable operation & maintenance cost, not including fuel cost
$FuelCost_i$, *TotFuelCost*	Fuel cost ($/MMBtu) of technology *i*; total fuel cost ($)	Fuel cost varies by technology
$TotCO_2TSCost$	Total CO_2 transport and storage cost	CO_2 transport and storage cost assumed to be $3/short ton and $7/short ton of CO_2 captured
NetCost	Net annual cost of electricity ($)	Total cost of electricity - offsets
$TotCO_2AllowCost$	Total CO_2 emissions allowance purchase cost ($)	# allowances purchased × price
$TotCO_2AllowOffset$	Total CO_2 emissions allowance sale offsets ($)	# allowances sold × price
TotRenewSetAsideOffset	Total offsets from selling renewable set-asides ($)	# allowances sold from renewable set-asides × price
$TotCO_2CaptureOffset$	Offsets from selling captured CO_2 for EOR ($)	CO_2 offsets sold for EOR × price
WACC	Weighted average cost of capital (%)	Discount rate of 7% is used
$CO_2EORPrice$	Sale price of captured CO_2 for enhanced oil recovery ($/short ton)	Sale price = $0/short ton, ref case
Reserve%	Capacity reserved (%) beyond peak demand	Reserve margin of 16.1%
WaterWithLimit	Water withdrawal limit (gals)	50% of 2012 level (1900 bn gals)

existing EGUs is estimated via:

$$TotFixCost = \sum_{i \in \{New,\ RenewSetAside\}} [Number_i \times Capacity_i \times FixCost_i] + \sum_{i \in Exist} [Fraction_i \times Number_i \times Capacity_i \times FixCost_i] \quad (3)$$

Total variable O&M cost and total variable fuel cost are estimated for all EGUs based on:

$$TotVarCost = \sum_i \sum_j [Gen_{ij} \times VarCost_i] \quad (4)$$

$$TotFuelCost = \sum_i \sum_j [Gen_{ij} \times HeatRate_i \times FuelCost_i] \quad (5)$$

Revenues from selling renewable set-aside pool allowances are calculated by multiplying the amount of electricity generated by the new set-aside by the incentive rate:

$$TotRenewSetAsideOffset = \sum_{i\in(RenewSetAside\}} \sum_{J} [Gen_{ij} \times RenewIncentive_{ij}] \tag{6}$$

The U.S. EPA (2015d) estimated the levelized cost of electricity (LCOE) for wind power: the cost normalized for advantages and disadvantages of the type and location for energy production. Assuming an average capacity factor of 85%, the LCOE of new NGCC is \$46.9/MWh. Similarly, assuming an average capacity factor of 36%, the LCOE of wind power is \$64.6/MWh. So we use the LCOE difference between these technologies, which is \$17.6/MWh, as the incentive rate. This rate is similar to renewable electricity Production Tax Credit for wind-powered EGUs that began construction after December 31, 2016 (U.S. DOE, 2017).

The revenue from selling captured CO_2 for EOR operations will decrease the total cost of electricity when this is implemented through the technology in the CCS system, based on the following relation:

$$\begin{aligned} TotCO_2CaptureOffset \;=\; & \sum_i \sum_j [Gen_{ij} \times HeatRate_i \times CO_2EmissionRate_i \\ & \times CO_2CaptureRatio_i \times CO_2EORPPrice_i] \end{aligned} \tag{7}$$

The *CO_2CaptureRatio* is the percent captured relative to the percent that is not. Captured CO_2 can be sold at a price that is established in the market. Note that the *CO_2EmissionRate* in this equation accounts for the rate with carbon capture for EGUs with CCS.

In addition, when a CO_2 emission allowance trading program is available, the allowance purchase cost (*CO_2AllowCost*) is the cost that an EGU faces to acquire a CO_2 emission allowance (*CO_2AllowBuy*) from the market. An EGU can also gain some allowance selling revenue (*CO_2AllowOffset*) if it sells its excess allowances (*CO_2AllowSell*) to the market for other EGUs to buy. An allowance rate (*AllowRate*) of \$13 per short ton is assumed in this model (U.S. EPA, 2015d).

The constraints in the model include:

- **Electricity demand and balance (1 constraint)**. Electricity generated must be equal to electricity demanded in each load strip:

$$\sum_i \sum_j [Gen_{ij}] = Demand_j, \quad \forall\, j \tag{8}$$

- **Load capacity for minimum and maximum electricity generation (5 constraints).** The different technology types may have different minimum and maximum load capacity. Coal-fired EGUs must have a capacity factor equal to or 50% greater in each period. All plants will have maximum load capacities that are determined by their effective load carrying capacity (ELCC). Existing EGUs may be retired so the maximum load capacities will be adjusted for only unretired EGUs. The constraints for existing plants with renewable energy resources are all bounded by the annual capacity factor defined for 2012. In addition, the 2012 annual capacity factor also is the upper bound for energy from nuclear plants, though availability varies geographically (U.S. EPA, 2013). A sample is:

$$Gen_{ij} \le ELCC\%_i \times Number_i \times Capacity_i \times 20\,Hours, \forall\ i, \ \forall\, j \tag{9}$$

Note that we use 20 h in the above equation because we discretized the one-year load duration curve into 438 load strips of 20 h each.

- **Reserve electricity generation capacity (1 constraint)**. Electricity generating capacity must be greater than or equal to that required by the peak demand, plus some additional reserve capacity:

$$\sum_i [ELCC_i \times Number_i \times Capacity_i] \ge (1 + Reserve\%)[max_j\ Demand_j] \tag{10}$$

- **Water withdrawal limit (1 constraint)**. When a limit is applicable, water withdrawals over a year must be less than a regulatory cap for a specific power generation technology:

$$\sum_i \sum_j [Gen_{ij} \times HeatRate_i \times WaterWithRate_i] \;\le\; WaterWithLim \tag{11}$$

- **Clean Power Plan compliance (7 constraints)**. The applicable constraints are for CO_2 emission caps for existing plants, CO_2 allowance trading, renewable set-asides, and output-based (for NGCC plants only) under EPA's CPP rules, so that a plant can emit CO_2 to the extent of its historical allowance, plus any other allowances it buys. If some EGUs are retrofitted with CCS, their CO_2 allocated allowances are divided proportionately to the capacity of EGUs with and without retrofit. The main constraint for allowance trading is:

$$\begin{aligned} & \sum_j [Gen_{ij} \times HeatRate_i \times CO_2EmissionRate_i] \le (Fraction_i \times CO_2Allow_i) + CO_2AllowBuy_i \\ & \quad + CO_2AllowOutputBased_i - CO_2AllowSell_i, for\ i \in \{ExistingCoal, OG\ Steam, NGCC\} \end{aligned} \tag{12}$$

The model applies an emission cap on total CO_2 emissions from affected existing and new plants. The emission limit sums the state's mass-based goal and new source complements proposed by the EPA.

The constraints of Eqs. (8)–(10) are EGU technical constraints for the operational requirements of a power fleet. The constraints of Eqs. (11 and 12) are energy policy constraints on water withdrawal and CO_2 emissions. There are other equations that we suppressed that are logical constraints so the math program will produce meaningful solutions. They are: variables for new EGUs should be greater than or equal to 0; the fraction of the number of existing EGUs must range from 0 to 1; other variables should be strictly positive.

Appendix F. Electricity generation share analysis

See Tables F1 here.

Table F1
Share of electricity generation by cooling technology under the pathway scenarios.

Scenarios and power tech	Wet-once-through	Wet-recirc	Hybrid	Dry
BAU				
Coal	54.3%	45.7%	0.0%	0.0%
NGCC	1.3%	86.5%	4.5%	7.6%
Nuclear	51.8%	48.2%	0.0%	0.0%
OG steam	99.3%	0.7%	0.0%	0.0%
All sources	32.3%	62.6%	1.9%	3.2%
CPS				
Coal	100.0%	0.0%	0.0%	0.0%
NGCC	10.2%	88.9%	0.3%	0.5%
Nuclear	51.8%	48.2%	0.0%	0.0%
OG steam	99.1%	0.9%	0.0%	0.0%
All sources	33.3%	66.1%	0.2%	0.3%
CPS + R				
Coal	100.0%	0.0%	0.0%	0.0%
NGCC	10.2%	88.9%	0.3%	0.5%
Nuclear	51.8%	48.2%	0.0%	0.0%
OG steam	99.1%	0.9%	0.0%	0.0%
All sources	33.3%	66.1%	0.2%	0.3%
CPS + RW				
Coal	48.9%	51.1%	0.0%	0.0%
NGCC	1.2%	97.3%	0.5%	0.9%
Nuclear	51.8%	48.2%	0.0%	0.0%
OG steam	59.1%	40.9%	0.0%	0.0%
All sources	17.4%	81.7%	0.4%	0.6%

Note. Shares of generation are for thermoelectric plants (coal, NGCC, nuclear, OG steam) that require cooling systems.

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