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Supplement Supporting PG&E/Ray Williams' Comments on State of the Science to Deeply Reduce GHG Emissions from California's Energy System

Additional submitted attachment is included below.

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VIA E-MAIL DOCKET@ENERGY.CA.GOV

California Energy Commission
Dockets Office, MS-4
Docket No. 15-IEPR-11
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Docket 15-IEPR-11: State of the Science on Scenarios to Deeply Reduce Greenhouse Gas Emissions from California's Energy System

Pacific Gas and Electric Company (PG&E) submits the following paper in support of comments made by Ray Williams at the California Energy Commission (CEC) workshop held on July 24, 2015 on the State of the Science to Deeply Reduce Greenhouse Gas Emissions from California's Energy System.

PG&E again thanks the CEC and their staff for the opportunity to contribute to this important topic.

Sincerely,

/s/

Valerie Winn

Impacts of State GHG Program Design in Implementing EPA's Proposed Clean Power Plan in California and the WECC

Authors: Jeff Brown[1], Ray Williams[1]

ABSTRACT:

U.S. EPA's proposed Clean Power Plan (CPP) would require states to develop plans to achieve EPA defined CO_2 emissions performance goals for their electric sector over the 2020-2030+ period. The proposed CPP provides significant flexibility to states in how the emission performance goals are achieved, including the option to develop multi-state plans to achieve EPA goals on a multi-state basis. States choices about how to achieve EPA's goals could have meaningful impacts on a number of important environmental (e.g., total electric sector CO_2 emissions) and economic (e.g., wholesale electric prices, natural gas prices, CO_2 abatement costs) metrics. To gain insight into how different state choices for implementing the CPP may affect these key environmental and economic metrics, we utilized ICF's Integrated Planning Model (IPM) to model several CPP implementation scenarios in the Western Electric System (i.e., WECC). The scenarios include CPP implementation approaches where states implement emissions (or emissions rate) trading with and without inter-state trading. In addition, we model scenarios where states make different choices about using mass- or rate-based programs to investigate potential effects of unaligned state programs. Our results provide insight into the potential benefits of regional approaches to implementing the CPP in the West.

INTRODUCTION:

On June 18th 2014, the US EPA proposed the Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act[2]. The CPP establishes a framework to reduce US CO_2 emissions from existing power plants by creating state specific average emission rate targets (e.g., lbs CO_2/ MWh) through EPA's application of the Best System of Emission Reductions (BSER). EPA derived the BSER targets based on assumptions about emission reduction potential from the following "Building Blocks":

1) Efficiency Improvements at coal-fired facilities
2) Re-dispatch from coal to gas
3) Expanded renewable generation and continued operation of existing and planned nuclear facilities
4) Expanded end-use energy efficiency

States would develop state or regional plans (or rely on a to-be-defined Federal plan) that specify the policy mechanism(s) used to achieve the interim (2020-29) and final targets (2030 and beyond). According to EPA modeling, compliance with the proposed targets would result in national CO_2 emission levels in 2030 that are 30% lower than 2005 levels.

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[1] Comments to the paper can be directed to the corresponding author at Jeffrey.Brown@pge.com. The opinions expressed here are solely of the authors and do not represent the views of Pacific Gas and Electric.

[2] "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," Federal Register, 18 June 2014: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

The CPP allows for a high degree of flexibility for states in implementing the rule including, but not limited to the choice of:

1) A rate (Tonnes/GWh) or mass (Tonnes) based performance metric
2) Policy mechanism(s) to achieve the performance metric
3) Single-state or multi-state compliance
4) Assumptions used to convert the rate-based target into a mass-based target
5) Whether to include new fossil-fired generation sources under the program

The flexibility offers an opportunity for states to design programs that facilitate cost-effective compliance with EPA's proposed targets. However, the flexibility also allows for states to make different choices in their compliance approaches, raising the concern that the resulting patchwork of state plans may increase emissions, raise costs, and distort power plant operational and siting incentives relative to a consistent, harmonized approach across states. In order to explore the potential impacts of some of these program designs on power markets in California and the WECC, PG&E working with ICF developed a suite of model runs that aim to establish how compliance outcomes and costs would differ under a range of policy options.

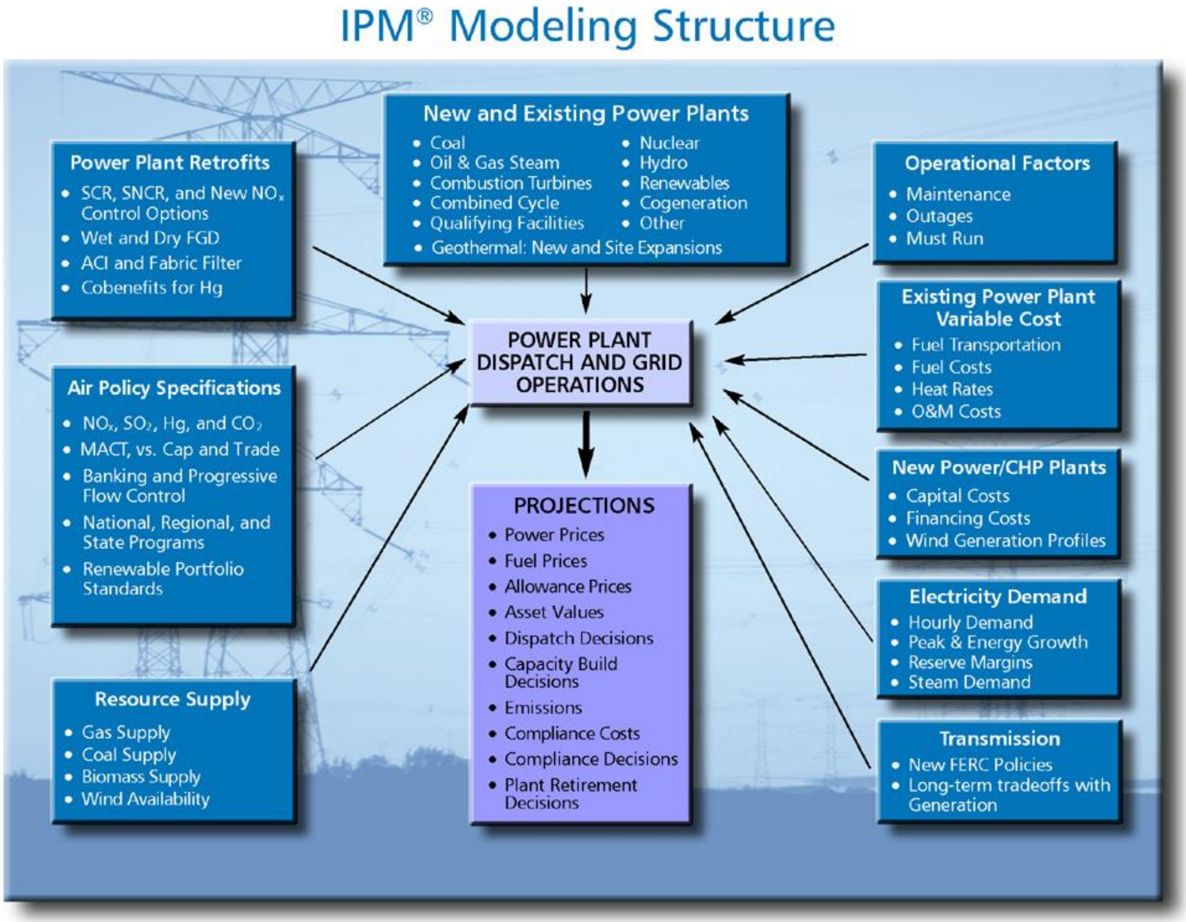
ANALYSIS APPROACH:

This analysis relies on ICF's Integrated Planning Model (IPM®) in order to establish a Business As Usual (BAU) Base Case as well as several CPP-compliant cases to better gauge the impact of state program design. IPM® provides a detailed representation of the US electric power sector, and is widely used by a range of private and public sector clients, in addition to being the platform used by EPA to support their analysis of the CPP as well as other major air regulations under the Clean Air Act.[3]

IPM® provides long-term projections of the behavior of existing power plants (including dispatch, retrofit and retirement) as well as the build out of new conventional and renewable power plants in order to meet demand for electric generation energy and capacity requirements while complying with specified constraints, including air pollution regulations, transmission constraints, and plant-specific operational constraints. The model includes a representation of emission control technologies, the ability to fuel switch, and alter regional generation and capacity mix. These changes are all dynamically linked to a representation of wholesale power market operation, and therefore allow IPM® to be used as a logically consistent framework through which to examine compliance outcomes, as shown in Figure 1 below.

[3] "EPA Power Sector Modeling," Environmental Protection Agency, 25 March 2015: http://www.epa.gov/powersectormodeling/

Figure 1



In order to construct the Base Case, the majority of the PG&E assumptions are based on EPA IPM v5.13 assumptions including[4]:

1) Load growth;

   EPA relied on the US Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2013 Reference Case projections of peak and energy demand using the NEMS model to develop the data used in EPA IPM v5.13. The data from AEO were mapped and translated to move from the aggregate NEMS level to the more granular IPM zones.[5]

2) Firm builds and retirements

   As part of the analysis surrounding the CPP, EPA developed and updated a version of the National Electric Energy Data System (NEEDS), which is a comprehensive list of existing

[4] "EPA's Power Sector Modeling Platform v.5.13," Environmental Protection Agency, 27 November 2013: http://www.epa.gov/airmarkets/programs/ipm/psmodel.html
[5] "3. Power System Operation Assumptions-3.2 Electric Load Modeling," Environmental Protection Agency, 2013: http://www.epa.gov/airmarkets/documents/ipm/Chapter_3.pdf

units, firmly planned additions to the system, and firmly planned retirements modeled under EPA IPM v5.13.[6]

3) Potential build costs and performance

IPM® is a capacity expansion model that allows for the option to build incremental conventional and renewable generation sources over the forecast horizon. EPA relied on EIA AEO 2013 assumptions on cost and performance assumptions to populate these build options.[7] Additionally, EPA developed IGCC and IGCC + CCS costs using a DOE NETL report.[8]

4) Retrofit costs and performance

In addition to the ability to build new capacity or retire existing units, IPM® also has a characterization of potential emission mitigation technologies, which can be installed on an economic basis on existing plants. EPA contracted the engineering firm of Sargent and Lundy to develop detailed cost and performance assumptions for retrofit options, which were then modeled within IPM v5.13.[9]

5) BSER targets

EPA relied on a spreadsheet exercise to develop BSER targets by adjusting 2012 historical emissions and generation profiles of each State to account for the impact of the four building blocks outlined above. These calculations and the final standards are provided under the EPA Technical Support Documents produced in support of the proposed rule.[10]

6) Renewable Portfolio Standard (RPS) targets

AEO 2013 aggregates existing state level RPS requirements into a series of constraints that are then modeled within the NEMS framework subject to cost containment provisions.[11] The resulting level of RE penetration is used to derive the aggregate RPS demand modeled by EPA in IPM v5.13.[12]

Additionally, PG&E updated the following assumptions for California:

1) Distributed Generation Solar Generation[13]

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[6] "4. Generating Resources," Environmental Protection Agency, 2013: http://www.epa.gov/airmarkets/documents/ipm/Chapter_4.pdf
[7] "4. Generating Resources," Environmental Protection Agency, 2013: http://www.epa.gov/airmarkets/documents/ipm/Chapter_4.pdf
[8] "Cost and Performance Baselines for Fossil Energy Plants," National Energy Technology Laboratory: http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies
[9] "5. Emission Control Technologies," Environmental Protection Agency, 2013: http://www.epa.gov/airmarkets/documents/ipm/Chapter_5.pdf
[10] "Clean Power Plan Proposed Rule: Goal Computation," Environmental Protection Agency, June 2014: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-goal-computation
[11] Energy Information Administration, U.S. Department of Energy, Assumptions to Annual Energy Outlook 2013: Renewable Fuels Module (DOE/EIA-0554(2010)), April 15, 2013, Table 13.2 "Aggregate Regional Renewable Portfolio Standard Requirements," http://www.eia.gov/forecasts/aeo/assumptions/pdf/renewable.pdf.
[12] "3. Power System Operation Assumptions," Environmental Protection Agency, 2013: http://www.epa.gov/airmarkets/documents/ipm/Chapter_3.pdf
[13] Please see Table 8 in appendix for details.

DG SPV generation levels were derived for WECC states using Transmission Expansion Planning Policy Committee (TEPPC) projections and for California from the 2014 Integrated Energy Planning Report (IEPR) and the E3 2013 Net Energy Metering Evaluation.

2) AB 32 Cap and Trade Prices[14]

AB 32 Cap and Trade allowance prices were calculated exogenously using ICF's proprietary multi-sectoral modeling framework through 2020. Prices were extrapolated using a 5% real growth rate between 2020 and 2050. The resulting price stream was then input into the analysis as a fixed price trajectory.

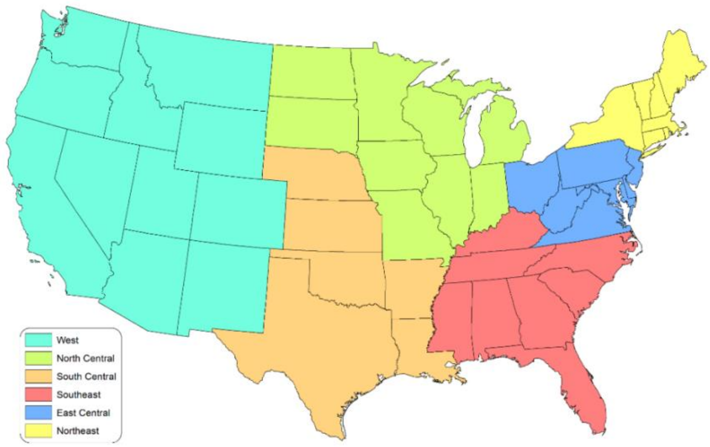
In addition to the Base Case, PG&E examined four policy cases as outlined in Figure 2 below.

Figure 2

Case Name	AB 32 Cap and Trade	Geographic Trading Regime	Emissions Rate Structure	Covered Sources	Energy efficiency
Base Case	Active through Forecast Horizon	AB 32 only; No 111(d)	N/A	N/A	N/A
Policy Case 1 **Patchwork Quilt**	Inactive 2020 and beyond for power sector	State Specific	State BSER Rate	RE, DG, Existing Fossil, At-Risk Nuclear	EPA Penetration[15]
Policy Case 2 **Regional Marketplace**	Inactive 2020 and beyond for power sector	WECC Regional Trading	State BSER Rate	RE, DG, Existing Fossil, At-Risk Nuclear	EPA Penetration
Policy Case 3 **Regional Blended Marketplace**	Inactive 2020 and beyond for power sector	WECC Regional Trading	Weighted Average Regional BSER Rate	RE, DG, Existing Fossil, At-Risk Nuclear	EPA Penetration
Policy Case 4 **CA C&T vs Regional Marketplace**	Active through Forecast Horizon	WECC Regional Trading minus CA	State BSER Rate + California AB 32 C&T	RE, DG, Existing Fossil, At-Risk Nuclear	EPA Penetration

[14] Please see Table 5 in appendix for details.
[15] "GHG Abatement Measures-Scenario 1," Environmental Protection Agency, June 2014: http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-ghg-abatement-measures-scenario1.xlsx

Regional Trading Groups under Modeled Scenarios



Policy Case 1 is closest to the "EPA Option 1 State" analysis[16], and examines state-specific compliance with state BSER targets as modeled by EPA. Incremental energy efficiency levels are consistent with EPA assumptions, and AB 32 Cap and Trade is assumed to be in effect for the power sector through 2019, with the CPP active in 2020 and beyond.

Policy Case 2 models the "EPA Option 1 Regional" analysis[17], and examines the impact of state-specific BSER targets, with the ability of states within a regional trading group (defined here as the 11 WECC states labeled "West" in the map above) to trade rate-based credits with each other in order to meet their BSER requirement. As with Policy Case 1, incremental energy efficiency levels are consistent with EPA assumptions, and AB 32 Cap and Trade is assumed to be in effect for the power sector through 2019, with the CPP active in 2020 and beyond.

Policy Case 3 departs slightly from the EPA modeled analysis, with states within the WECC having to meet a weighted average regional BSER target and the ability to trade rate-based credits between states within a regional trading group. Incremental energy efficiency remains consistent with EPA levels, while AB 32 Cap and Trade is assumed to be in effect for the power sector through 2019, with the CPP active in 2020 and beyond.

Policy Case 4 reflects the impact of California "going it alone," with AB 32 Cap and Trade remaining in effect for the power sector over the forecast horizon in California, and all other WECC states having to meet an individual BSER target, but with the ability to trade with other states within the WECC (similar to Policy Case 2).

Modeling Specifications in Policy Cases Analyzed

Energy Efficiency:

[16] "Proposed Clean Power Plan, Option 1-State," Environmental Protection Agency, 2014: http://www.epa.gov/airmarkets/documents/ipm/Option%201%20State.zip
[17] "Proposed Clean Power Plan, Option 1-Regional,"Environmental Protection Agency, 2014: http://www.epa.gov/airmarkets/documents/ipm/Option%201%20Regional.zip

The Policy Cases all include the same pre-determined levels of incremental energy efficiency, consistent with the levels of energy efficiency projected by EPA under the modeling of the CPP.[18] Energy efficiency is assumed to ramp up over time, starting from historical benchmark levels, before eventually reaching 1.5% of incremental sales per year in each of the states.

AB 32 Cap and Trade:

AB 32 Cap and Trade allowance prices were calculated exogenously using ICF's proprietary multi-sectoral modeling framework through 2020. Prices were extrapolated using a 5% real growth rate between 2020 and 2050. The resulting price stream (see Table 5) was then input into the analysis as a fixed price trajectory which is levied on CO_2 emissions associated with electricity generated in State. All imports into California are charged the GHG price assuming the unspecified emission rate specified by ARB of 0.428 Metric Tonnes CO_2e/MWh.[19] Policy Cases 1, 2 and 3 assume that the AB 32 GHG price remains active only through 2019, while Policy Case 4 assumes that the AB 32 GHG price remains active throughout the forecast horizon.

Compliance with the BSER Target:

In Policy Case 1, qualifying generators in each state are assigned to a constraint, which holds the aggregate emissions rate (defined as the sum of all CO_2 emissions from the facilities divided by total generation from the facilities) of that universe of units must be less than or equal to the BSER target for that state as modeled by EPA. In other words, IPM® optimizes generation, dispatch, builds and retirements to minimize total production cost and serve load while also meeting the BSER target specified (and other transmission, emission and unit-level constraints). This is reflected in compliance outcomes: for instance the generation mix in a particular state does not exactly correspond to that specified by EPA in deriving the BSER target[20], even though the BSER target itself must be met.

Policy Case 2 extends the setup under Policy Case 1 by allowing facilities within a regional trading program to trade compliance instruments. Hence each state must meet its BSER target, but it may do so by buying or selling compliance instruments from units located in states that are within the same regional trading program.

Policy Case 3 simplifies the trading structure in Policy Case 2 by setting a single BSER target for all facilities within a regional trading group.

Policy Case 4 explores the interaction of AB 32 Cap and Trade and the CPP, by assuming that all states other than California are in a regional trading program with state level BSER targets (as in the Policy Case 2 setup), but that the AB 32 GHG prices (including on imported electricity) remain active in California throughout the forecast horizon. Hence all emissions in California and imports into California are charged a fixed GHG price (as outlined above).

[18] "EPA v5.13 Base Case Documentation Supplement to Support EPA's Proposed Carbon Pollution Guidelines for Existing Electric Generating Units," Environmental Protection Agency, 12 June 2014: http://www.epa.gov/airmarkets/documents/ipm/EPA%20Base%20Case%20v5%2013%20Documentation%20Supplement%20for%20CPP_6_12_14.pdf

[19] "Electric Power Entity Reporting Requirements Frequently Asked Questions (FAQs) for California's Mandatory Greenhouse Gas Reporting Regulation," California Air Resources Board, 22 April 2015: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/epe-faqs.pdf

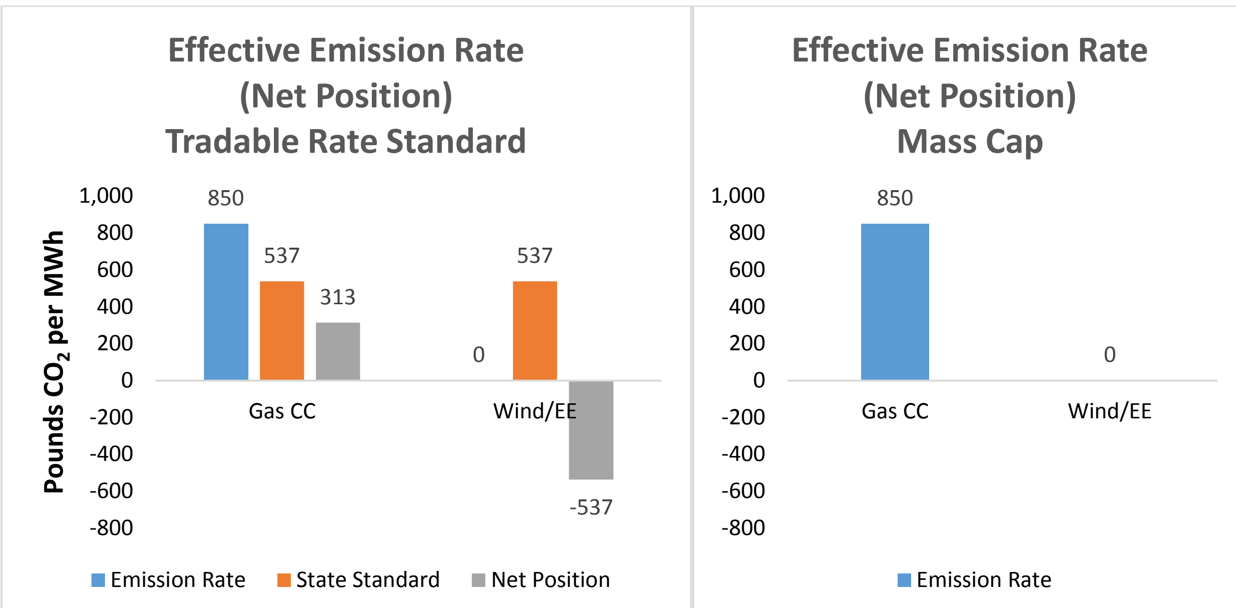
[20] "Clean Power Plan Proposed Rule: Goal Computation," Environmental Protection Agency, June 2014: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-goal-computation

Differential Impacts of tradable rate-based standard and a mass based cap on wholesale power prices:

Under a traditional cap and trade regime, every ton of CO_2 emitted from qualifying facilities is charged at the market clearing allowance price. However, under a tradable rate based standard the credit allowance price is charged based on the difference between the emission rate of each particular qualifying facility and the BSER target. This difference is also referred to as the effective emission rate or net position of the facility.

As shown in Figure 3, this means that under a tradable rate based standard, units that emit below the BSER target of 537 lb/MWh effectively have a negative net position per MWh, while those that generate above the BSER target have a positive net position per MWh. In the case of a traditional mass cap, the net position per MWh of any qualifying facility is equal to the emission rate of the unit.

Figure 3



In order to calculate the $/MWh impact of a given credit allowance price for a particular unit, it is necessary to first calculate the net position of the unit and multiply this term by the credit or allowance price, as illustrated in Figure 4. For example, under a tradable rate based approach with a BSER target of 537 lb/MWh and a credit price of $11/Tonne, an NGCC unit with an emission rate of 850 lb/MWh would incur a $1.56/MWh dispatch cost adder. The same unit would incur a $4.24/MWh adder under a mass cap with an $11/Tonne allowance price. Similarly, a non-emitting wind unit would earn a credit of $2.68/MWh under a BSER regime with a target of 537 lb/MWh and a credit price of $11/Tonne. Under a mass cap, the unit would incur a $0/MWh adder. It is worth noting that the spread between the NGCC unit and the wind unit remains the same in either case assuming the credit price is the same in both cases.

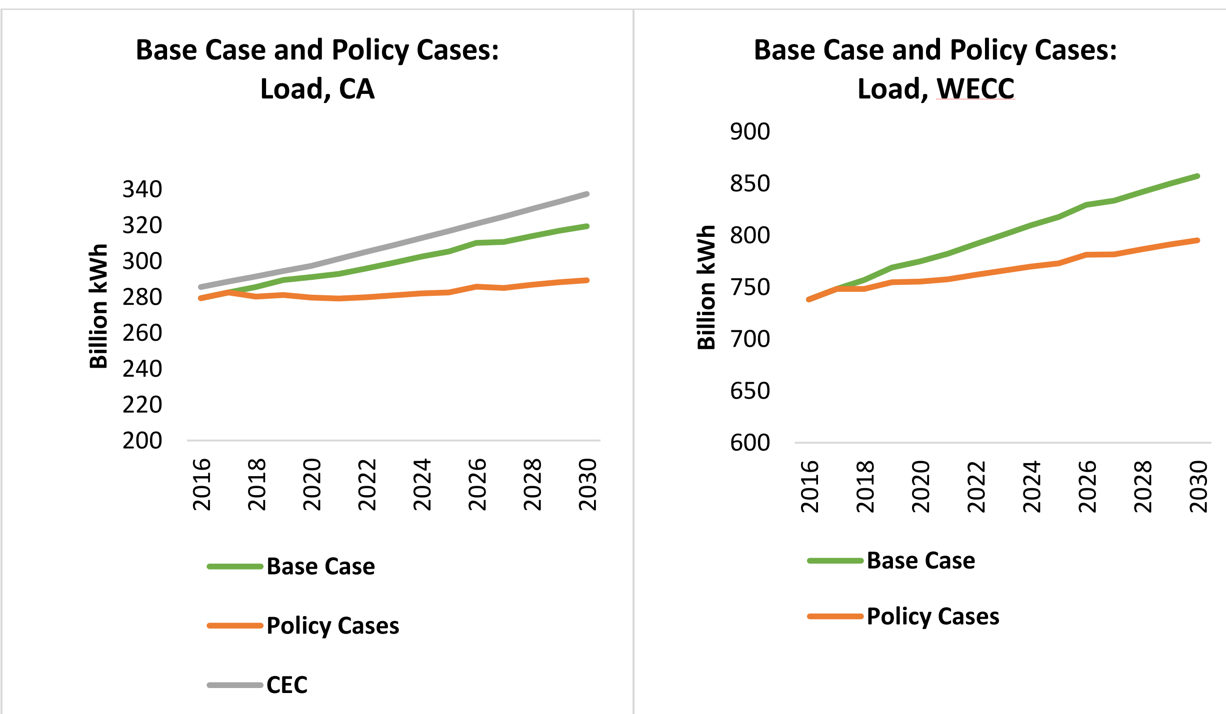
Figure 4

Program Type	CO_2 Price ($/Tonne)	CO_2 Adder: Gas CC ($/MWh)	CO_2 Adder: Wind/EE ($/MWh)	Spread between Gas CC and Wind Unit
		= Net Position $\left(\frac{lb}{MWh}\right)$ * Credit Price $\left(\frac{\$}{Tonne}\right)$ * $\left(\frac{Tonne}{lb}\right)$		
Mass Cap	11	$(850) * \left(\frac{11}{2204}\right)$ = 4.24	$(0) * \left(\frac{11}{2204}\right)$ = 0	4.24 - 0 = 4.24
Rate-Based Trading	11	$(850 - 537) * \left(\frac{11}{2204}\right)$ = 1.56	$(0 - 537) * \left(\frac{11}{2204}\right)$ = (2.68)	1.56 - (2.68) = 4.24

SUMMARY RESULTS:

At the levels assumed by EPA, energy efficiency remains one of the major pathways towards compliance with the CPP targets. As shown in Figure 5 below, California load in both the Base and Policy Cases starts below the levels projected under the California Energy Commission (CEC) forecast. In the Policy Cases, California load declines roughly 9% by 2030 relative to the Base Case as a result of the incremental energy efficiency penetration. Similarly, incremental energy efficiency penetration results in a 7% decline in load in 2030 in the Policy Cases relative to the Base Case at the WECC level.

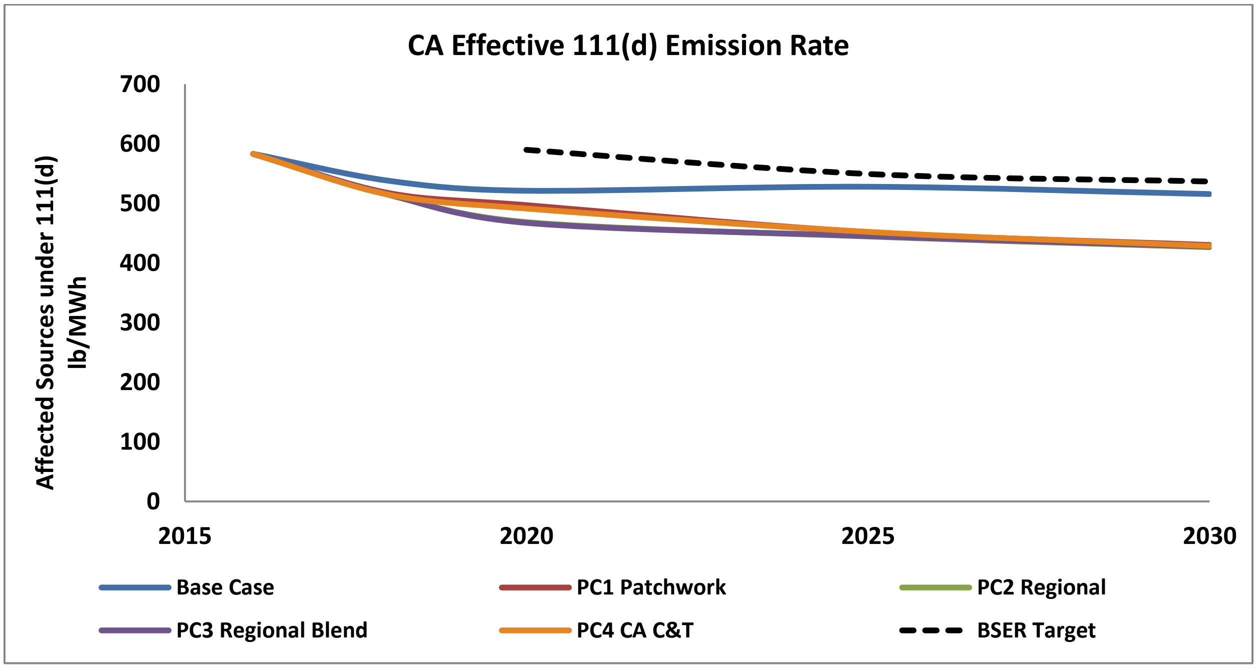
Figure 5



Note: Base and Policy Case forecasts from EPA. All forecasts are net of solar DG. CEC 2013 Mid-Case; Data beyond 2024 extrapolated based on 2020-2024 growth rate.

This incremental energy efficiency is also in large part responsible for the lower levels of CO_2 emissions in the Policy Cases relative to the Base Case. It is important to note that CO_2 adjusted emission rates in California in all the Policy Cases modeled are substantially below levels projected under the Base Case (Figure 6), and California (in-state) emissions remain at or below the illustrative 2030 mass-based targets developed by EPA (Figure 7).[21] Consistent with EPA modeling in support of the Clean Power Plan, biomass fuel was assigned an emissions factor of 195 lb/MMBtu.[22] All results cited in this paper therefore include positive CO_2 emissions from biomass.

Figure 6



Note: BSER Target reflects the rates calculated by EPA (2020: 590 lb/MWh, 2025: 550 lb/MWh, 2030-50: 537 lb/MWh); the emissions rates shown represent in-state emissions and generation only – in line with the CPP

Figure 7

[21] "Clean Power Plan Proposed Rule: Translation of the State-Specific Rate-Based CO2 Goals to Mass-Based Equivalents," Environmental Protection Agency, November 2014: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-translation-state-specific-rate-based-co2

[22] "EPA v5.13 Base Case Documentation Supplement to Support EPA's Proposed Carbon Pollution Guidelines for Existing Electric Generating Units," Environmental Protection Agency, 12 June 2014, pp. 2: http://www.epa.gov/airmarkets/documents/ipm/EPA%20Base%20Case%20v5%2013%20Documentation%20Supplement%20for%20CPP_6_12_14.pdf

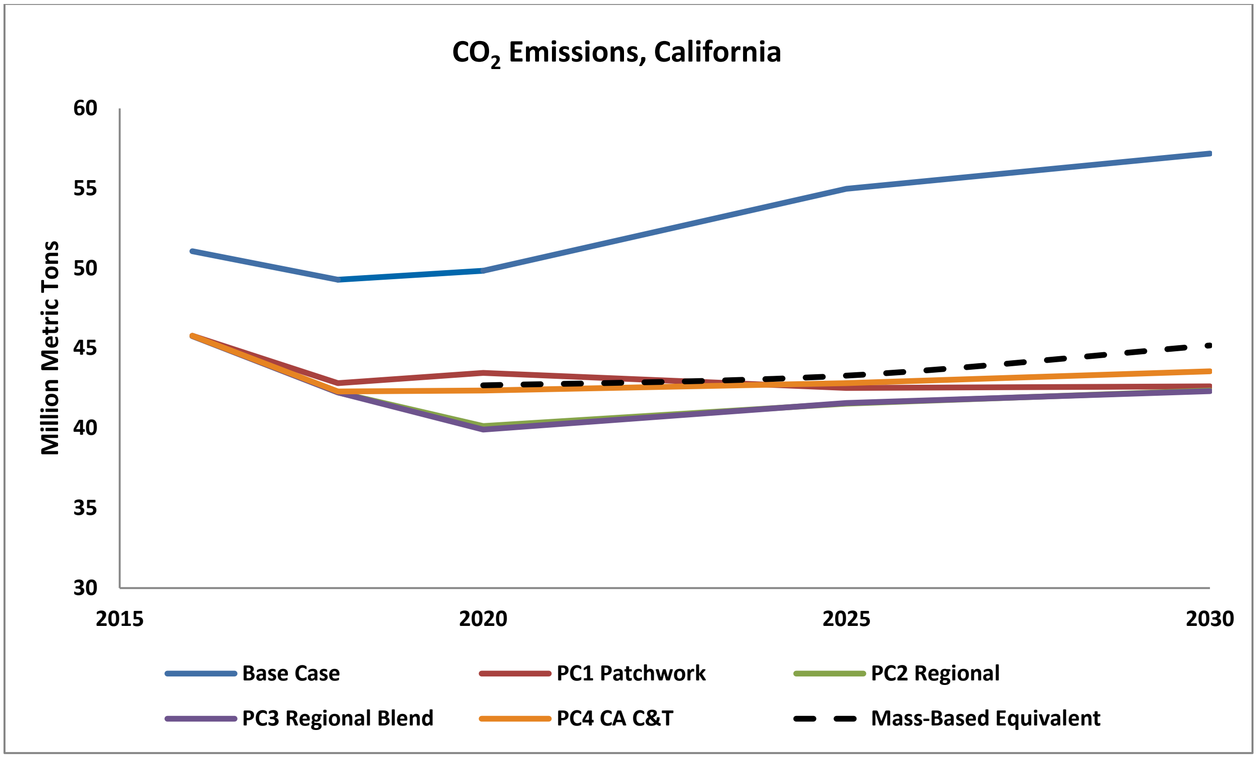
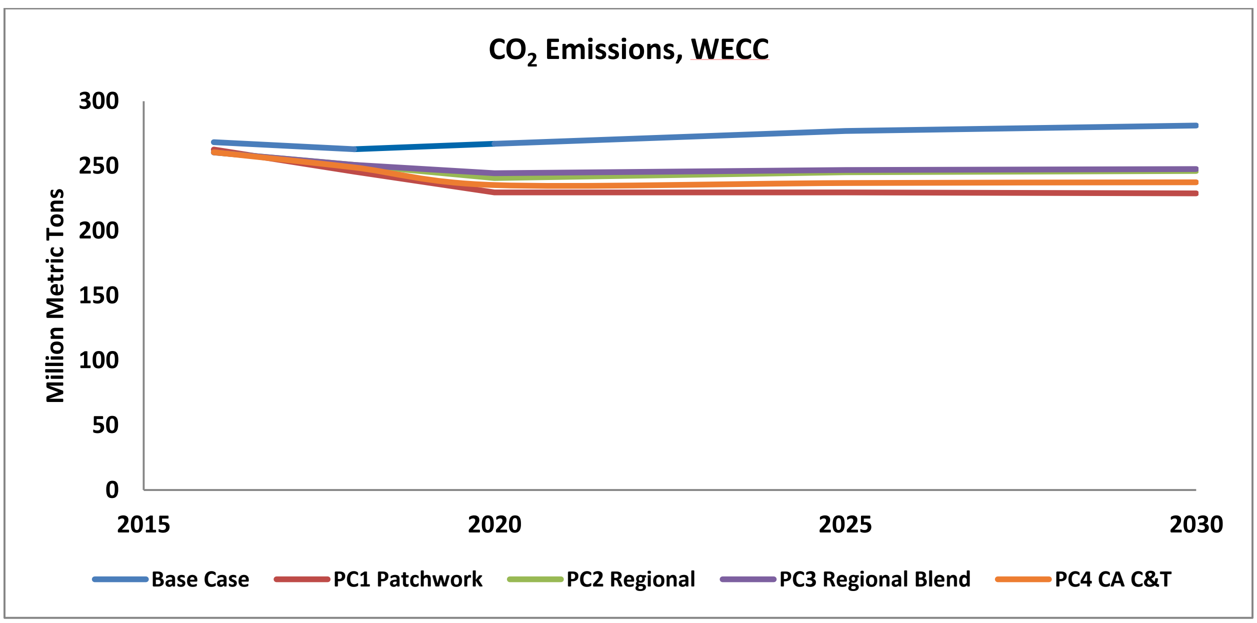
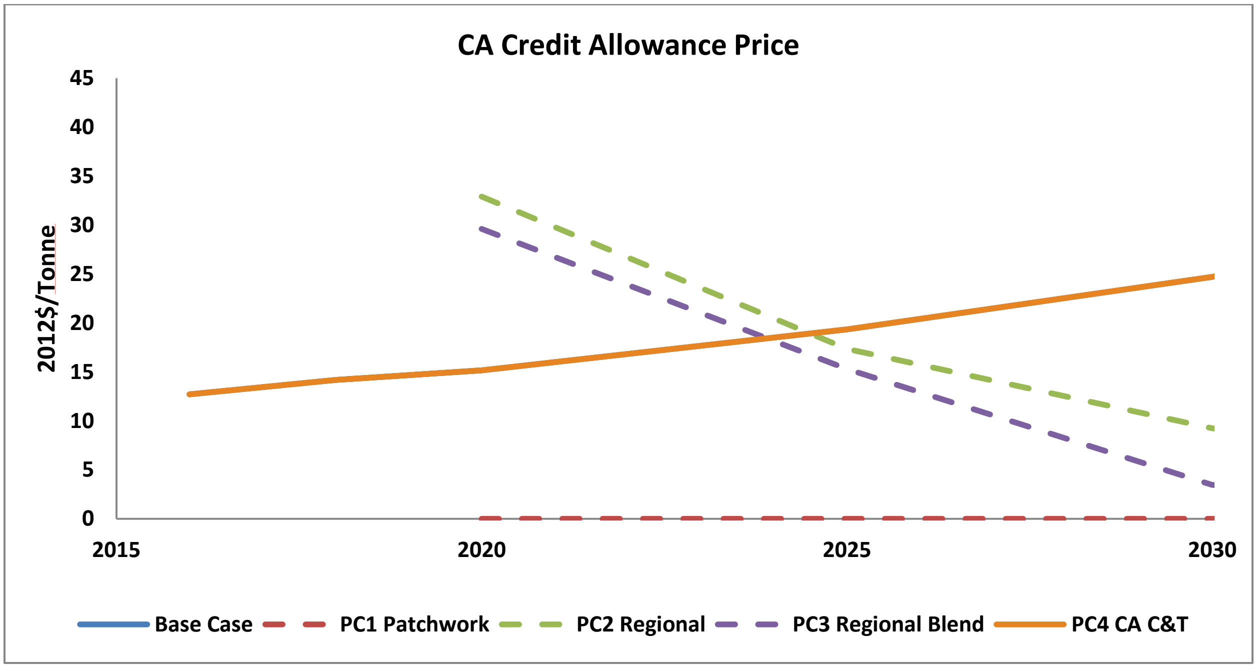


Figure 8



Under the Base Case and Policy Case 4 (CA C&T), AB 32 Cap and Trade is assumed to remain in effect for the power sector throughout the forecast horizon. In Policy Cases 1, 2 and 3, AB 32 Cap and Trade is assumed to remain in place for the power sector through 2019, with the CPP rate trading policy in place in 2020 and beyond. As shown in Figure 9 below, credit prices in Policy Case 1 are $0/tonne beginning in 2020 due to existing state policy (e.g., the 33% RPS), increased energy efficiency and increased imports from surrounding states. Credit prices in Policy Cases 2-3 remain above Policy Case 1 due to regional trading and indicate that the proposed CPP targets would require emissions reduction beyond the base case from WECC states as a whole.

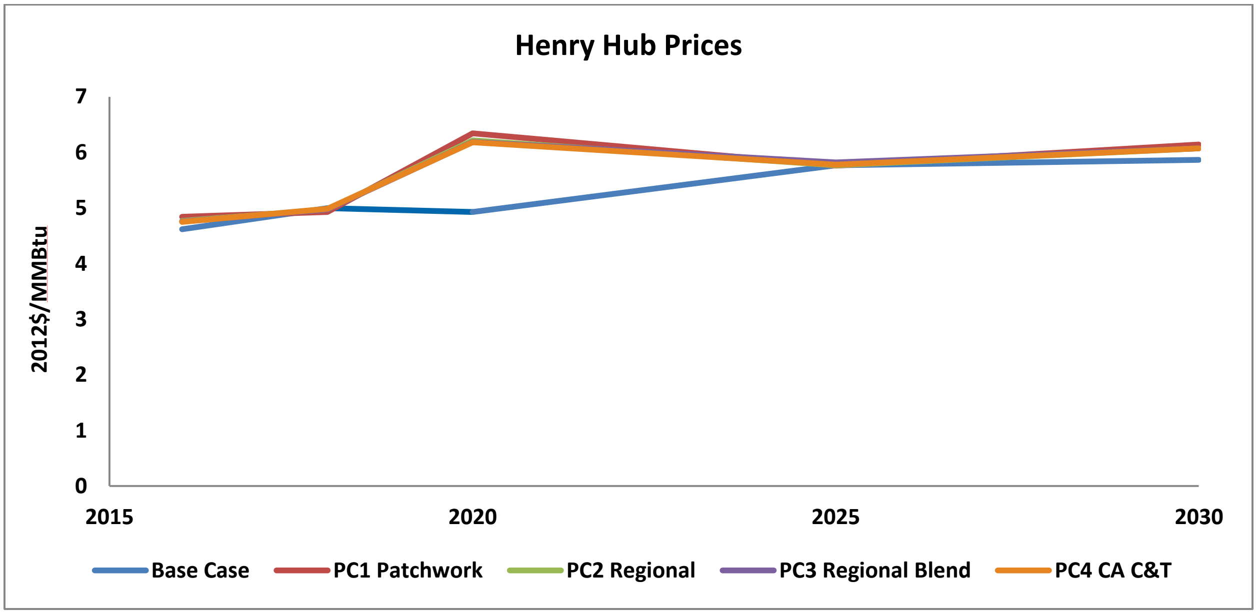
Figure 9



Note: Allowance prices under a mass-cap (solid lines) and credit prices from a tradable rate-based system (dashed lines) impact dispatch costs and wholesale electricity prices differently.

In the near-term fuel switching away from coal-fired generation and towards NGCC generation plays a major role in compliance with the targets. Over time, the increasing penetration of energy efficiency and renewable energy dampens the demand for natural gas. This is illustrated in Figure 10, which shows the Henry Hub price for each scenario. Prior to the implementation of the CPP, in the 2016 and 2018 run years, Henry Hub gas prices are very similar between the Base and Policy Cases. In 2020, the incremental demand for Natural Gas results in a roughly $1/MMBtu premium in Henry Hub prices in the Policy Cases relative to the Base Case. In 2025 and beyond, prices between the Base and Policy Cases are again very similar, due in large part to the increased availability of incremental energy efficiency over this period.

Figure 10



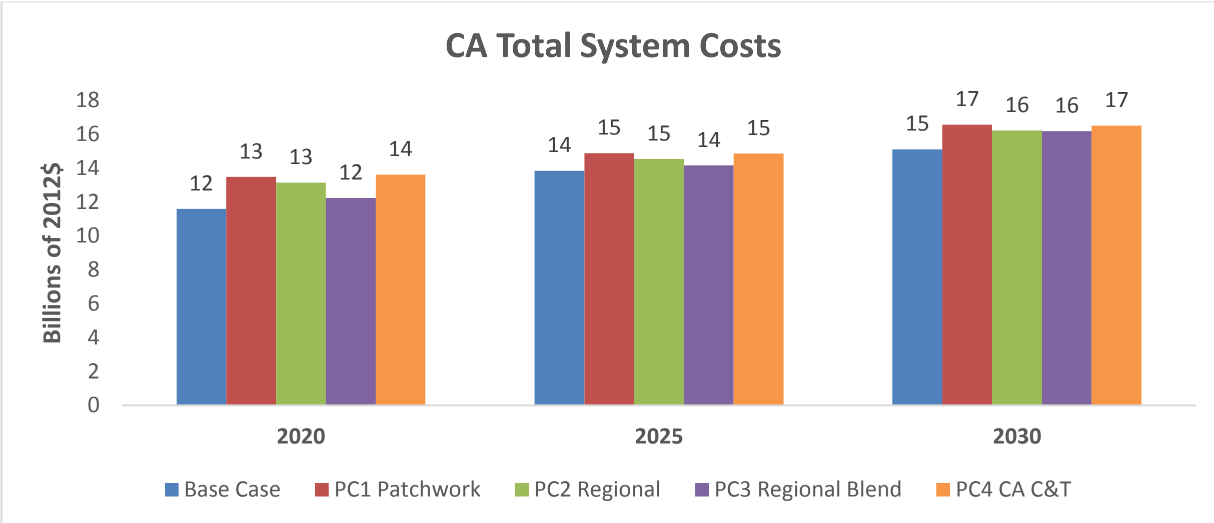
In order to better quantify the total compliance costs of the various Policy Cases, we examine the Total System Cost of each Policy Case relative to the Base Case. The Total System Cost is defined as follows:

Total System Cost = Levelized Capital Cost + Fuel Cost + O&M Cost + CPP Credit value + Energy Efficiency Cost + Power Purchase Cost

As shown in Figure 11, costs are very similar between the Base and Policy Cases in 2016 and 2018 in California (prior to the introduction of the CPP). In 2020 and beyond, once the CPP is in effect, the Policy Cases show significantly higher Total System Costs than the Base Case. Of the four Policy Cases, Cases 2 and 3 have the lowest costs in California due to the ability to sell credits out of state to the rest of WECC. States in Policy Case 3 must meet a weighted average rate, whereas states under Policy Case 2 must meet individual state BSER targets. In both cases, states can trade with one another. Since the average BSER target under Policy Case 3 is higher than CA's BSER target (which CA remains below in all policy cases), Policy Case 3 results in a higher revenue stream to covered facilities in CA than Policy Case 2 for a given CO_2 allowance price. This in turn drives CA system costs lower in Policy Case 3 as compared to Policy Case 2 in the 2020-2025 period. Post 2025, Policy Case 3 allowance prices are lower than Policy Case 2 allowance prices by an amount sufficient to erode this advantage, and total costs equilibrate between the cases.

Figure 11[23]

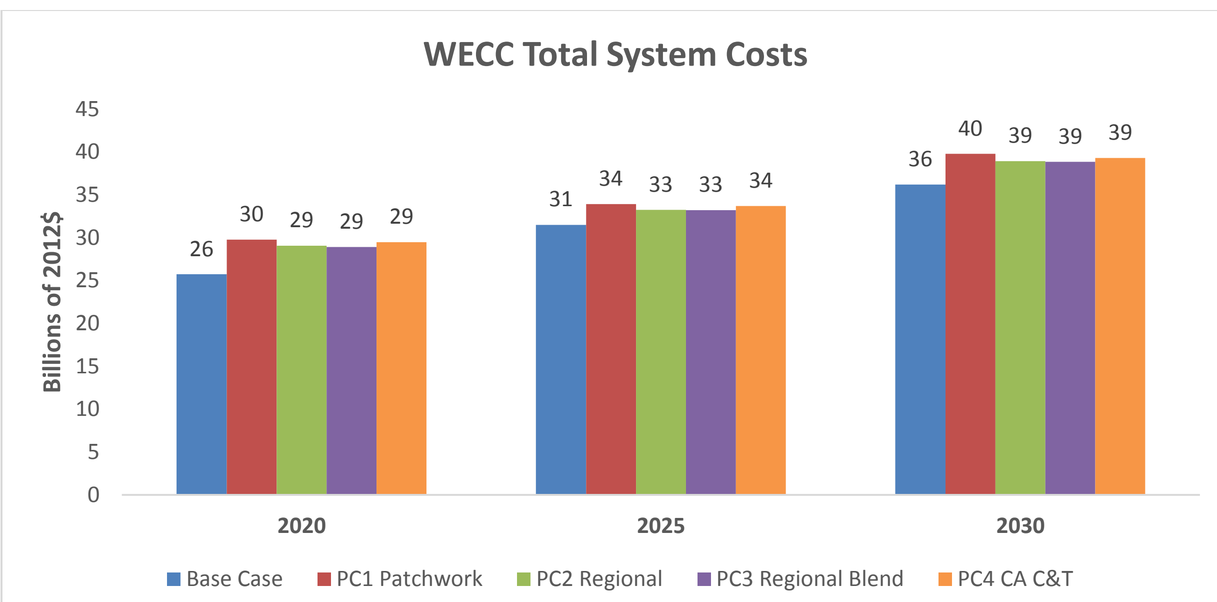
[23] See Table 9 in Appendix for details



Similar trends persist at the WECC level, with Policy Case 1 and 4 incurring the highest Total System Costs as a result of lower levels of emission allowance trading across states.

The WECC states (with the exception of SD) are all in the same regional trading program in Policy Cases 2 and 3. The sum of the allowance value at the trading region is equal to zero, since states generating credits (and gaining revenue) are counterbalanced by the states buying the credits (and incurring a cost). Hence the difference between Policy Case 2 and Policy Case 3 is more muted at the WECC level than at the California level. Policy Case 3 incurs slightly lower costs than Policy Case 2, driven in part by more efficient dispatch across the trading region as a result of units facing the same emission standard regardless of location within the trading group.

Figure 12



INSIGHTS:

1. California's existing GHG policies position it well to comply with the CPP:

California has already taken a range of steps towards reducing greenhouse gas emissions, and as a result is well-positioned to comply with the proposed EPA targets. In fact, as shown in Figure 6 above, across the Base Case and all of the Policy cases, the effective emission rate in California remains below the proposed CPP targets. Moreover, as outlined in Figure 7, the total mass of CO_2 emissions in California remains at or below the illustrative EPA mass caps by 2030. This is highlighted by the fact that Policy Case 1 (state specific standards without trading) results in a zero dollars per ton credit price in California.

2. Regional trading lowers WECC-wide compliance costs:

As shown in Figure 12, WECC-wide compliance costs are highest when the WECC states comply individually and are lower when the policy design allows regional trading of compliance instruments.

3. Regional trading results in modestly higher CO_2 emissions WECC wide:

CO_2 emissions in all the policy cases are projected to achieve similar levels of reductions from the Base Case. However CO_2 emissions remain highest in Policy Case 2 and Policy Case 3, which include the option to trade regionally, while Policy Case 1 projects the lowest levels of CO_2 emissions amongst the cases modeled.

Under Policy Case 1, each individual state must meet its own BSER target through exclusively local emission reduction and abatement measures. Under Policy Case 2, each state must meet its own BSER target, but can source reductions from any state within its trading group.

Hence any states that are able to comply with the EPA targets without the need for incremental reductions can under a regional trading program supply this level of reductions to states that would otherwise need to pursue abatement options. Therefore total emissions may be higher under a regional trading program if some states within a regional trading program would have been long relative to their BSER targets in the absence of trading.

4. Regional trading allows California to generate a revenue stream while also lowering compliance costs throughout WECC:

Based on the modeling conducted, California is in a long position relative to the proposed CPP targets, in large part due to past and current state policies to reduce electricity sector GHG emissions. As a result, under the rate-based, regional trading approaches modeled under this analysis (Policy Case 2 and 3), California could sell some of its credits to states that have not undertaken similar policies and are facing significant emissions reduction costs under the CPP. This in turn would generate a significant earnings stream for California, while other WECC states would benefit by being able to purchase the credits generated by California as a result of its low emissions profile at a cheaper cost than pursuing equivalent levels of reduction in-state.

5. Regional trading with a regional average trading rate results in a higher revenue stream for California than regional trading around individual state BSER targets:

Policy Case 2 features a state-specific BSER target with trading between states, while Policy Case 3 features a regional average BSER target across the WECC. As such, the effective target that California units face under Policy Case 2 is lower than that under Policy Case 3, and a given reduction in emission intensity of covered sources in California in Policy Case 3 generates a larger number of emission rate credits than in Policy Case 2. As a result of this, the revenue stream to California (CPP Credit Value) is higher under Policy Case 3 than Policy Case 2. This is reflected in the lower Total System Costs in Policy Case 3 relative to Policy Case 2 for California during the CPP period (as shown in Figure 11).

6. Adoption of rate-based trading by the rest of WECC and a continuation of AB 32 Cap and Trade for the power sector results in higher compliance costs for California:

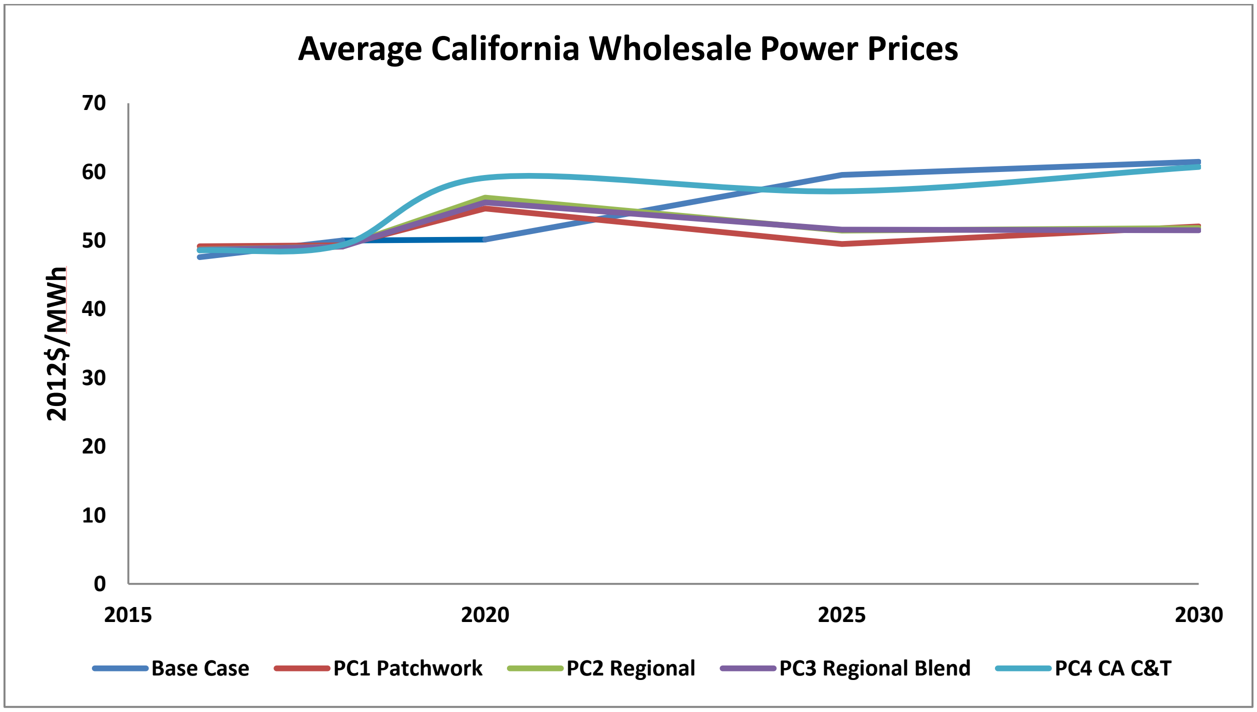
At the California level, emissions are lowest and costs are highest in Policy Case 4, as a result of imports into that state being "double tagged". Policy Case 4 assumes that AB 32 Cap and Trade continues throughout the forecast horizon, with all CO_2 emissions associated with California in-state generation, and imports into California being charged the AB 32 Cap and Trade price. Additionally, all the remaining states must meet their state specific BSER target as specified under the proposed rule, while being able to trade within their respective regional trading group. As such imports into California must pay both the AB 32 Cap and Trade price as well as the CPP credit price in the state in which they originate, thus increasing import costs into California relative to the other cases.

***7. Tradable rate based standards have different wholesale price impacts than mass-based caps*:**

As outlined earlier, a CO_2 allowance price under a mass cap is levied on all emissions from a qualifying generator. On the other hand, a credit allowance price under a tradable rate based approach is only charged on the difference between the emissions rate of the covered generator and the relevant BSER target (the unit's net emissions position per MWh). Hence the impact on the cost of dispatch of units is very different under the two policy constructs.

This differential impact on marginal dispatch costs is evident when viewing the projected wholesale prices under the various policy scenarios and the Base Case. As shown in Figure 13 below, average wholesale power prices are low in Policy Cases 2 and 3 despite a relatively higher market clearing price, reflecting California's ability to generate revenue under the tradable rate based regime. Conversely, prices are highest under Policy Case 4, as a result of the mass based AB 32 Cap and Trade carbon price in California and the continuation of CPP in neighboring states. It is also worth noting that wholesale power prices are tempered by the presence of incremental energy efficiency in the policy cases as compared to the Base Case.

Figure 13



8. Energy Efficiency is a key driver of CO_2 reductions:

Energy efficiency plays a major role in both reducing the total compliance costs under the CPP, as well as driving overall emissions trajectories lower in the various Policy Cases modeled. As shown in Figure 14 below, energy efficiency penetration is significant across WECC in the Policy Cases, resulting in a 9% reduction in California demand by 2030 from Base Case levels, and a 7% reduction in demand from Base Case values at the WECC level. In addition to reducing overall demand, given the current proposed rule, every avoided MWh of electricity stemming from energy efficiency uptake is treated as an hour of emissions free generation to be counted in the denominator of the state BSER calculation. In other words, energy efficiency is able to generate credits, which can then be used to allow units that have an emissions rate higher than the target BSER to continue to operate.

Figure 14

Cumulative Savings from Energy Efficiency

Energy Efficiency (GWh)	2016	2018	2020	2025	2030
CA	-	5,314	11,434	22,845	30,030
WA	-	2,291	4,687	10,419	14,131
OR	-	1,272	2,603	5,424	7,232
ID	-	265	543	1,305	1,803
NV	-	529	1,224	3,505	5,083
AZ	-	2,042	4,782	9,243	12,162

UT	-	356	1,286	3,202	4,461
CO	-	1,014	2,387	5,638	7,812
WY	-	133	324	1,382	2,284
MT	-	238	555	1,454	2,056
SD	-	75	188	796	1,300
NM	-	298	867	2,413	3,501
WECC	**-**	**13,827**	**24,760**	**50,095**	**67,139**

9. Gas Prices continue to increase over the forecast horizon:

As shown in Figure 10, Henry Hub gas prices are projected to rise from $4.6/MMBtu in 2016 to $5.9/MWh in 2030 (in 2012$) in the Base Case, reflecting increasing demand growth over the forecast horizon (for example, to replace capacity and generation from retiring coal plants). In the policy cases, gas prices show a roughly $1/MMBtu premium in 2020 relative to the Base Case, reflecting incremental gas demand in response to the CPP, which incentivizes fuel switching away from coal and towards natural gas. Over time natural gas prices equilibrate with the values projected under the Base Case, as incremental energy efficiency reduces power sector demand for natural gas. This may raise some concern over the potential for stranded costs as a result of infrastructure investments made to supply gas demand in 2020 which may not be utilized to the same levels over subsequent years.

CONCLUSIONS

The CPP provides a framework through which to reduce GHG emissions from the power sector. While EPA's proposed rule outlines a host of changes to the existing generation mix including greater reliance on natural gas fired generation, efficiency improvements at coal-fired generators, incentives for nuclear units to continue to remain online, and expanded renewable and energy efficiency deployment, the proposed rule also allows for substantial flexibility in the particular approach taken to complying with the final targets up to individual States.

While California tends to remain below the proposed EPA emission rate standards across all the cases studied under this analysis, the choice of program design in California and the rest of the WECC holds significant bearing on the total compliance costs borne by California and other WECC states. In particular, regional trading regimes involving all the WECC states result in similar levels of emissions reductions at the WECC level as in the case where each state individually complies with its BSER target, but at a lower cost. This is driven by the ability of states with relatively lower abatement costs being able to sell their excess reductions to states with relatively higher abatement costs. However, as a result, some states may emit more and others less than they would under a State specific BSER regime without regional trading. At the same time, regional trading in the WECC while California "goes it alone" and maintains the AB 32 Cap and Trade regime results in higher costs as imports into California are charged both the AB 32 Cap and Trade price as well as the CPP credit price in the state in which they originate.

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APPENDIX

Table 1: Base Case and Policy Case Load Assumptions

	CA Energy Demand (Billion KWh)			WECC Energy Demand (Billion KWh)	
Year	**Base Case**	**Policy Cases**	**CEC**	**Base Case**	**Policy Cases**
2016	279	279	286	738	738
2017	283	283	289	748	748
2018	286	280	292	757	748
2019	290	281	294	769	755
2020	291	280	297	775	755
2021	293	279	301	782	758
2022	296	280	305	792	762
2023	299	281	309	801	766
2024	303	282	313	810	770
2025	305	283	317	818	773
2026	310	286	321	830	781
2027	311	285	325	833	782
2028	314	287	329	842	787
2029	317	288	333	850	791
2030	319	289	337	857	795

Table 2: California Effective 111(d) Rate (lb/MWh)

	2016	2018	2020	2025	2030
Base Case	583	538	521	528	516
PC1 Patchwork	583	517	497	452	430
PC2 Regional	583	514	469	445	427
PC3 Regional Blend	583	514	468	445	428
PC4 CA C&T	583	514	492	452	429
BSER Target			590	550	537

Table 3: California In-State Emissions - Millions of Metric Tonnes

	2016	2018	2020	2025	2030
Base Case	51	49	50	55	57
PC1 Patchwork	46	43	43	43	43
PC2 Regional	46	42	40	42	42
PC3 Regional Blend	46	42	40	42	42
PC4 CA C&T	46	42	42	43	44
Mass-Based Equivalent (EPA Cap)			43	43	45

Table 4: WECC Emissions - Millions of Metric Tonnes

	2016	2018	2020	2025	2030
Base Case	268	263	267	277	281
PC1 Patchwork	263	245	230	230	229
PC2 Regional	261	251	241	245	246
PC3 Regional Blend	261	251	244	247	247
PC4 CA C&T	261	249	235	237	237

Table 5: California Credit Prices - 2012 $/Tonne

	2016	2018	2020	2025	2030
Base Case (AB 32)	13	14	15	19	25
PC1 Patchwork			0	0	0
PC2 Regional			33	17	9
PC3 Regional Blend			30	15	3
PC4 CA C&T	13	14	15	19	25

Table 6: Henry Hub Prices - 2012$/MMBtu

	2016	2018	2020	2025	2030
Base Case	4.6	5.0	4.9	5.8	5.9
PC1 Patchwork	4.8	4.9	6.3	5.8	6.1
PC2 Regional	4.8	5.0	6.2	5.8	6.1
PC3 Regional Blend	4.8	5.0	6.2	5.8	6.1
PC4 CA C&T	4.7	5.0	6.2	5.8	6.1

Table 7: Average CA Wholesale Power Prices - 2012$/MMBtu

	2016	2018	2020	2025	2030
Base Case	48	50	50	60	61
PC1 Patchwork	49	49	55	49	52
PC2 Regional	49	49	56	51	52
PC3 Regional Blend	49	49	56	52	51
PC4 CA C&T	49	49	59	57	61

Table 8: California DG SPV Bounds

Year	CA DG SPV (GW)
2016	4.8
2018	5.0
2020	5.1
2025	5.3
2030	5.6

Table 9: California Total System Costs

CA Total System Costs (Billions of 2012$)	2016	2018	2020	2025	2030
Base Case	10.67	11.24	11.59	13.86	15.12
PC1 Patchwork	10.77	11.58	13.49	14.89	16.57
PC2 Regional	10.83	11.55	13.15	14.54	16.22
PC3 Regional Blend	10.83	11.55	12.25	14.17	16.18
PC4 California C&T	10.81	11.58	13.62	14.87	16.51

Table 10: WECC Total System Costs

WECC Total System Costs (Billions of 2012$)	2016	2018	2020	2025	2030
Base Case	22.48	24.33	25.71	31.49	36.20
PC1 Patchwork	22.68	24.92	29.77	33.91	39.77
PC2 Regional	22.50	24.82	29.04	33.23	38.91
PC3 Regional Blend	22.48	24.80	28.89	33.21	38.82
PC4 California C&T	22.46	24.78	29.46	33.69	39.28