

State of California  
AIR RESOURCES BOARD

**CALIFORNIA'S  
PROPOSED COMPLIANCE PLAN  
FOR THE  
FEDERAL CLEAN POWER PLAN**

*UNDER CLEAN AIR ACT SECTION 111(d)*

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## **1. Introduction and Background**

Power plants are the largest stationary source of greenhouse gases (GHGs) nationally, and among the largest sources in California. To address these emissions, which contribute to climate change, U.S. EPA has issued federal Clean Air Act regulations directing the states to reduce greenhouse gas emissions from existing covered electrical generating units (EGUs). These regulations, known as the Clean Power Plan (CPP), will reduce GHG emissions from affected sources by nearly one-third from 2005 levels when fully implemented. In addition to supporting a cleaner, more efficient power sector, the CPP will also yield significant co-benefit pollutant reductions of criteria pollutants with corresponding public health benefits.

Under state law, the Air Resources Board (ARB or Board) is charged with preparing California's CPP compliance plan. ARB staff has prepared this Proposed Compliance Plan with the assistance of an interagency working group including the California Energy Commission (CEC) and California Public Utilities Commission (CPUC).

The Proposed Plan is designed to comply with CPP requirements, while ensuring smooth operation of California's existing suite of climate programs, including the Cap-and-Trade Program. The suite of programs, many adopted pursuant to the Global Warming Solutions Act of 2006, AB 32 (Nunez, Chapter 488, Statutes of 2006), are yielding GHG reductions and the State is on track to achieve the 2020 statewide target and accomplish our longer-term climate goals.

Accordingly, this Proposed Plan is based upon the continued operation of the Cap-and-Trade Program. The Cap-and-Trade Program establishes a declining limit on major sources of GHG emissions, and it creates a powerful economic incentive for major investment in cleaner, more efficient technologies. Amendments to the Cap-and-Trade Regulation, and the related Mandatory Reporting Regulation, are being considered to support the CPP, as well as to support the operation of these state programs from 2020 forward. As the Board considers those amendments, it will also consider this Proposed Plan based upon them. This connected regulatory and planning package is designed to propose an integrated path forward for California climate policy as it relates to CPP.

Many complementary energy sector programs, including California's energy efficiency standards and Renewable Portfolio Standard further support these reductions. Their effects are accounted for in the Cap-and-Trade Program. As California continues to seek greenhouse gas reductions from the electric power sector, these complementary state programs will help ensure that the State meets and exceeds CPP targets.

For these reasons, ARB is proposing to comply with CPP requirements via the "state measures" approach, with the Cap-and-Trade Program as the state measure. Under this approach, EGUs participating in the Cap-and-Trade Program will have a federally-enforceable obligation to comply with key Program requirements, while other participants in the market program will continue to have only state-enforceable obligations. Cap-and-Trade Program compliance (along with compliance with the

supporting requirements of ARB's MRR) will also ensure CPP compliance. As required by the CPP, a federally-enforceable backstop measure is proposed for inclusion in the Cap-and-Trade Program for CPP-affected EGUs, which will further ensure that federal emission targets are met. However, as the modeling described in this Proposed Plan explains, it is very unlikely that the backstop would be triggered.

This Proposed Plan identifies the elements of California's approach to CPP compliance and includes a modeling demonstration showing that California will be able to comply with CPP requirements. Specifically, the substantive elements of the Proposed Plan principally include:

- An identification of all CPP affected EGUs in California and a calculation of California's federal emissions limits under the CPP
- Amendments to MRR to ensure that all EGUs covered by the CPP report and maintain records consistent with CPP requirements.
- Amendments to the Cap-and-Trade Regulation aligning Cap-and-Trade compliance periods with the CPP.
- Amendments to the Cap-and-Trade Regulation requiring, as a federally-enforceable matter, CPP affected EGUs to maintain compliance with its terms, including compliance instrument surrender requirements.
- A federally-enforceable backstop program, based on tradeable compliance instruments, that will be triggered in the unlikely event that affected EGU emissions exceed federal limits, and which will require all affected EGUs to reduce their emissions to come back into compliance.
- Extensive modeling and analysis demonstrating that these measures will ensure compliance with the CPP.

This Proposed Plan will undergo extensive public comment and review, in accordance with state and federal law. As the Board considers the overall shape of California's post-2020 climate programs, this Proposed Plan demonstrates that those programs can also assure compliance with federal requirements, capitalizing on the progress California has already made, and streamlining regulatory requirements. Staff anticipates that the Board will consider the Plan as part of its overall evaluation of climate programs going forward, and will present the Plan for final approval in Spring 2017, in coordination with other proposed measures.

### 1.1 Key CPP Requirements

U.S. EPA established the CPP based upon its authority under Section 111(d) of the federal Clean Air Act (CAA) (42 U.S.C. § 7411(d)). Section 111 of the CAA charges U.S. EPA with establishing standards of performance for sources in industry categories

whose pollution may reasonably be anticipated to endanger public health or welfare. Each standard is to reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that has been adequately demonstrated. The electrical power sector is among these sectors, so U.S. EPA has periodically set standards of performance for EGUs.

U.S. EPA has determined that GHGs are among the pollutants for which Section 111 standards must be set (see 74 Fed. Reg. 66,496 (Dec. 15, 2009)). Accordingly, in fall 2015, U.S. EPA issued standards for new and modified EGUs (see 80 Fed. Reg. 64,510 (Oct. 23, 2015)). That action also created a legal duty for U.S. EPA to issue emissions guidelines for existing EGUs (those which commenced construction on or before January 8, 2014) to the states and to implement a process for submission of state plans to achieve those guidelines. (See 42 U.S.C. § 7411(d)(1) and 40 C.F.R. Part 60, Subparts B and C). U.S. EPA did so simultaneously (see 80 Fed. Reg. 64,662 (Oct. 23, 2015)). These emission guidelines are contained in the CPP, which is codified as Subpart UUUU of 40 C.F.R. Part 60.

To determine the required emissions reductions for existing EGUs, U.S. EPA conducted an extensive BSER analysis. It ultimately identified three “building blocks” of BSER based on actions that EGUs, states, and the energy sector are already undertaking that reduce GHGs from existing EGUs. These are (1) heat rate improvements at affected coal-fired steam EGUs, (2) substituting increased generation from lower-emitting existing natural gas for generation from higher-emitting units, and (3) substituting increased generation from new zero-emitting renewable energy for generation from fossil-fuel-fired EGUs (80 Fed. Reg. 64,667). U.S. EPA applied these building blocks to modeled EGU emissions nationally to establish final allowable CO<sub>2</sub> emissions rates in 2030-31 for two classes of existing EGUs: Fossil-fuel-fired steam generating units, which have a 1,305 lbCO<sub>2</sub>/MWh rate, and stationary combustion turbines, which have a 771 lbCO<sub>2</sub>/MWh rate (40 C.F.R. Part 60 Subpart UUUU, Table 1).

U.S. EPA calculated interim and final corresponding mass targets for each covered state, based on the application of the required emission rates to that state’s fleet of existing EGUs. As is discussed in more detail below, ARB staff has recalculated these goals to account for the final list of affected EGUs. The final 2030-1 target is 100,598,722 short tons CO<sub>2</sub>e in 2030-31, with an interim target of 423,990,560 short tons CO<sub>2</sub>e over the 2022-2029 period.

These targets are to be achieved over several interim compliance periods. These CPP periods are January 1, 2022 – December 31, 2024; January 1, 2025 – December 31, 2027; January 1, 2028 – December 31, 2029 and January 1, 2030 – December 31, 2031, and every two years thereafter (40 C.F.R. § 60.5880).

Affected states may submit state compliance plans for review and approval by U.S. EPA. U.S. EPA will implement a federal compliance plan in any affected state that does not submit a satisfactory plan. Initial compliance plans were set to be due in September 2016, with possible extensions up to September 2018 (40 C.F.R. § 60.5760), although



these deadlines have been temporarily stayed by the U.S. Supreme Court, pending resolution of litigation on the CPP. The federal compliance periods begin January 1, 2022, and the full reductions required by the CPP must be achieved by December 31, 2031, and maintained thereafter. ARB staff anticipates submitting this Proposed Plan, if approved by the Board, to U.S. EPA once the stay has been lifted.

U.S. EPA provided states with considerable flexibility on how to reach the federal targets. States have the discretion to meet either rate or mass targets, to plan individually or jointly, and to design plans that are a mix of federally-enforceable “emission standards” and state-enforceable “state measures” (see 40 C.F.R. § 60.5740).

The CPP allows economy-wide emissions trading systems, like California’s Cap-and-Trade Program, to be used for CPP compliance if they are submitted as “state measures” plans (See, e.g., 80 Fed. Reg. 64,851-53). ARB staff is proposing to use this state measures approach in order to integrate CPP compliance within California’s Cap-and-Trade Program.

This plan type allows for operation of an economy-wide state emissions trading system as a compliance approach, provided that the state includes certain federally enforceable emission standards for CPP-covered electricity generating units (affected EGUs) at the outset, as well as a “backstop” standard that guarantees compliance with federal targets if the larger trading system underperforms (See 40 C.F.R. § 60.5740(a)(2)-(3)). Sources are free to use any instruments accepted in the state trading system to comply with these emission standards. This includes a range of “flexibility mechanisms,” including offsets and linked market compliance instruments (see 80 Fed. Reg. 64,891). Within the larger economy-wide program, requirements of the state program on sources not regulated by the CPP (i.e., other industrial sectors) are not federally enforceable, but the requirement that affected EGUs comply with the state cap-and-trade system are federally enforceable.

The federally enforceable “backstop” standard required under this approach must bring affected EGU smokestack emissions into compliance with the federal standard if the combination of the “state measure” (the economy-wide trading system) and related emission standard (the requirement that EGUs participate in that trading system) does not perform as expected when compared to a glide path established by the state that is consistent with the federal targets (See 40 C.F.R. § 60.5740(a)(3)). The backstop would be triggered by emissions exceedances above interim targets that the state sets for each compliance period, consistent with the overall federal targets.

Finally, U.S. EPA has also proposed a Clean Energy Incentive Program, as an optional additional component of the Clean Power Plan. ARB continues to be interested in this program, and will evaluate it, taking further regulatory or planning action as appropriate. ARB staff anticipate that more information on the Clean Energy Incentive Program will be available before this Plan is finalized, and will consider any additional information carefully.

In addition to these fundamental structural requirements, state measures plans must address several other CPP requirements. These include requirements addressing allocation, banking, and borrowing (see 40 C.F.R. § 60.5815); requirements for reporting and recordkeeping at affected EGUs (see 40 C.F.R. § 60.5860); reporting requirements for the State (see 40 C.F.R. § 60.5870); and permitting needs at affected EGUs (see 80 Fed. Reg. 64,920).

## 1.2 ARB Responsibilities and Interagency Collaboration

ARB is the designated as the State air pollution control agency for all purposes set forth in federal law (Health & Safety Code § 39602), which include preparing CAA Section 111(d) compliance plans. ARB has broad regulatory and planning authority to fulfill this charge (see *id.* §§ 39600, 39601). ARB is also the State agency “charged with monitoring and regulating sources of greenhouse gases ... in order to reduce emissions” (*id.* § 38510). ARB staff therefore prepared this Proposed Plan for consideration by the Board.

Recognizing that other state agencies have primary responsibility for other aspects of the electricity system and crucial expertise, ARB staff developed the Proposed Plan in close collaboration with staff at CEC and CPUC. An interagency staff working group collaborated on technical analysis and modeling, with staff from all three agencies providing critical expertise. As is discussed in more detail below, CEC staff also led modeling work to demonstrate compliance with the CPP.

ARB staff also sought and received extensive public feedback at a series of public workshops, beginning in 2014, before CPP was finalized. ARB staff also solicited input from its Environmental Justice Advisory Committee and will continue to conduct public outreach as described in the public process section of this document. Staff also briefed CalEPA’s Tribal Advisory Committee on CPP Compliance Plan development.

## 2. Identification of California’s Affected EGUs

Pursuant to 40 C.F.R. § 60.5740(a)(1), and using the CPP’s applicability criteria, ARB staff has identified all CPP affected EGUs in the state and provides that identification list, and information on associated emissions. Further information is available in Appendix A to this Proposed Plan.

### 2.1 Overview of Electrical Generation Technologies and CPP Affected EGUs in California

California has a diverse portfolio of electrical generation resources. A long focus on clean generation has resulted in one of the lowest-emitting power sectors in the country. The state is on track to meet a 33 percent renewable portfolio standard by 2020. In addition, California is currently planning the next round of renewable generation

deployment to meet a 50 percent renewable target by 2030, as required by recently adopted Senate Bill 350 (SB 350)<sup>1</sup>.

California's fossil fleet is changing.<sup>2</sup> Most large steam generating units in California are located in coastal areas with easy access to cooling water. However, due to stringent water quality entrainment requirements, some units are being replaced by combustion turbines or are shutting down to meet "Once through Cooling" requirements designed to protect marine life from cooling water intake and discharge from power plants.<sup>3</sup> Despite these retirements, many natural-gas fired units, of several different designs, remain. ARB staff has carefully reviewed the CPP's applicability to these remaining units.

## 2.2 CPP Applicability Requirements

As required by § 60.5740, California's Proposed Plan must identify all affected units consistent with § 60.5845. EGUs that must be addressed by the plan include any steam generating unit, integrated gasification combined cycle (IGCC) or stationary combustion unit that meets the conditions in § 60.5845. These provisions define affected units as fossil-fueled units that commenced construction on or before January 8, 2014, serve a generator or generators connected to a utility power distribution system with a nameplate capacity greater than 25 MW-net; and have a base load rating greater than 250 MMBtu/hr heat input (either alone or in combination with any other fuel). In addition, stationary combustion turbines<sup>4</sup> must be either a combined cycle unit or a combined heat and power unit. Simple cycle turbines regardless of heat input or

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<sup>1</sup> For more information on the Clean Energy and Pollution Reduction Act (SB350) see Appendix F and [https://leginfo.ca.gov/faces/billNavClient.xhtml?bill\\_id=201520160SB350](https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350)

<sup>2</sup> In addition to fossil facilities, California has approximately 36 operating biomass plants. U.S. EPA determined that none of these were affected units. ARB staff also determined that all biomass facilities use less than 10 percent fossil fuel (natural gas) and concurs that these units are, therefore, exempt from being affected facilities.

<sup>3</sup> The State Water Resources Control Board (State Water Board) implements the Federal Clean Water Act section 316(b) requirements regarding cooling water intake structures to control and/or mitigate entrainment and impingement of marine life related to power generating facility intake structures. On May 4, 2010, the State Water Board adopted a Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Policy). See [http://www.swrcb.ca.gov/water\\_issues/programs/ocean/cwa316/](http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/) for more information.

<sup>4</sup> A stationary combustion turbine includes all equipment including the turbine engine, the fuel, air and lubrication and exhaust gas systems, control systems (except emissions control equipment) heat recovery system, fuel compressor, heater and or pump, post combustion control emission control technology and any ancillary components and sub-components comprising any simple cycle combustion turbine, combined cycle unit and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment.. Stationary means the turbine is not self-propelled or intended to be propelled while performing its function. It may be mounted on a vehicle for portability. If a turbine burns any solid fuel, it is considered a steam generating unit. Further, combined cycle units are defined as an electric generating unit that uses a stationary combustion turbine from which heat from the turbine exhaust gases is recovered by a heat recovery steam generator.

generating capacity that do not utilize waste heat are exempt from the requirements of this regulation.

To determine the status of each EGU, ARB staff applied CPP definitions. As defined by the CPP, a steam generating unit means any furnace, boiler, or other device that combusts fuel and produces steam plus any integrated equipment that produces electricity or useful thermal output to the affected facility or auxiliary equipment. Nuclear steam generators are not included.

Therefore, when considering if a combined cycle turbine is an affected unit, staff considered the megawatt (MW) ratings from the turbine engine's generator and well as the MW rating of the steam turbine generator associated with the heat recovery steam generator (HRSG) portion of combined cycle turbines. In order to list these combined MW ratings, ARB staff used the same naming convention used by the Department of Energy's Energy Information Administration (EIA). Specifically, naming convention for a combined cycle combustion *turbine* part is listed as a "CT" and the combined cycle turbine *steam* part as a "CA." A combined cycle single shaft (where a combustion turbine and steam turbine share a single generator) is designated as a "CS". A turbine that is used as a combined heat and power units is designated as a (GT) (does not include the combustion turbine part of a combined cycle).

The CPP also provides eight exemptions from its affected unit definition in § 60.5850. These are:

- 1) Units that are subject to 40 CFR Part 60, Subpart TTTT – the federal greenhouse gas new source performance standard (NSPS) for new, modified, and reconstructed units, as a result of commencing construction after the applicability date.
- 2) Steam generating units with federally enforceable limits that limit net electric generation to less than one-third of potential net electric sales or 219K MWhs or less
- 3) Units that are capable of combusting greater than 50% non-fossil fuel and that limit fossil fuel use to 10 percent or less (as measured by annual capacity factor).
- 4) Combined heat and power units that have a federally enforceable limit or historically had annual net electric sales that were no more than the design efficiency multiplied by the potential electric output or 219K MWhs or less;
- 5) Units that serve a generator with a capacity of 25 MW or less
- 6) Combustion turbines that are not capable of combusting natural gas (for instance, because they not connected to a natural gas pipeline)
- 7) Municipal waste combustors that are subject to NSPS Subpart Eb
- 8) Commercial or industrial solid waste incinerators that are subject to NSPS Subpart CCCC.

### 2.3 Identification of Affected Units

Consistent with the CPP, ARB staff used the best data available, including information reported to the California Energy Commission (CEC) and outreach to the owners and operators of California’s EGUs, to identify these units.

In order to determine applicability of the CPP to California EGUs, ARB staff sent a letter on September 16, 2015 to all potentially-affected EGU facility owners stating that ARB believed their units could be affected units. Staff requested that each owner respond to ARB attesting to their view on the applicability of the CPP to their units, confirming or correcting the data in ARB’s possession. If owners or operators believed that some units were not affected units, staff requested that they provide documentation demonstrating any exemption claimed.

Based on information received and staff research, the affected units ARB staff identified differ somewhat from those identified in the initial list of units published by U.S.EPA. In addition, the MW ratings of some units differ from U.S.EPA’s list based upon the best data available. Although the affected EGU list is largely the same, some units which U.S. EPA believed to be affected EGUs are not covered by the CPP; others which were not identified as affected units have been added to the list of affected units. These units are described below. The list of units (and their associated emissions) can be found in Appendix A. Complete documentation of these efforts, including correspondence with EGU owners and operators, is included in Appendix B. Figure 1 is a map of the affected units located in California. Table 1 summarizes the changes made to the default list of affected units provided by the U.S. EPA:

**Table 1- Changes in the Affected EGU List**

<b>Category</b>	<b>Update</b>	<b>#</b>	<b>Total MW</b>	<b>Total 2012</b>
Under Construction	EPA Included – CA Excluded	2	80.5	388,912
Coal Steam Turbine	EPA Included – CA Excluded	2	81.0	0
Oil/Gas Steam Turbine	EPA Included – CA Excluded	1	81.6	161,544
Natural Gas Combined Cycle	EPA Included – CA Excluded	7	265.0	876,518
<b>Total</b>	<b>Removed from EPA</b>	<b>12</b>	<b>508.1</b>	<b>1,426,974</b>
Oil/Gas Steam Turbine	EPA Excluded – CA Included	10	486.6	352,250
Natural Gas Combined Cycle	EPA Excluded – CA Included	32	1,719.1	5,315,826
<b>Total</b>	<b>Added to EPA List</b>	<b>42</b>	<b>2,205.7</b>	<b>5,668,076</b>

**Figure 1 – Map of affected facilities in California**



#### 2.4 Data on Affected EGUs in California

Staff reviewed the list of affected units and modified the list as discussed above. Based on the revised list, staff reviewed the effect of these changes on three main uses of the data: 1) used to recalculate the state emissions goal; 2) to determine a 2014 emissions inventory as U.S. EPA requires; and 3) to determine compliance with the revised goals.

### *Data Used in State Goal Computation*

CPP goals for California are based on year 2012 data. As described above, the list of affected units used to determine CPP goals for California is different than what was published in the federal Register. The list of affected units for the goal calculation (as corrected by staff) results in a total of 246 affected units located at 93 facilities and owned by 67 different companies, plus three units that are still under construction. Of the 246 units, there are 62 steam generating units, 121 combustion turbines and 63 steam turbines.

### *Data Used in CPP Emission Inventory*

Of the 246 affected units identified for purposes of calculating the goal for California, 26 units (3,985 MWs) have shut down since 2012.<sup>5</sup> These include 16 steam units (3,298 MWs) and six natural gas-fired combustion turbines and the associated four steam turbines (688 MWs). These units are affected units for the purposes of determining California's goal (which was based on year 2012 data). For the 2014 inventory, in Appendix A, staff provides a list all affected units and calculate the emissions from the list of affected emission units based on operation in 2014.<sup>6</sup> The list also includes the 3 units that are affected units, but have not begun operation.

### *Characteristics of Affected EGUs*

There are a total of 249 units that will be subject to the CPP (upon completion of 3 units in late 2016). These 249 affected units will total 38,015 MWs of installed capacity; will consist of 93 facilities owned by 67 different companies. They range in size from 4 MWs to 806 MWs. The number of affected units by prime mover type is listed below in Table 2.

**Table 2 – Affected Units by Prime Mover Type**

Prime Mover	Quantity	Total MWs Installed	Size Range MWs
Steam Plants	64	15,951	30 – 806
Combustion Turbine (CT)	94	11,567	21 – 214
Combustion Turbine Steam Part (CA)	64	7,066	4 – 324
(CT Plus CA)	(158)*	18,633*	4 – 324
Combined Heat and	20	1,181	40 – 78

<sup>5</sup> Note that the modeling conducted to demonstrate compliance includes these affected units as well as units that are projected to shut down based on age.

<sup>6</sup> As described above there are 249 units that will be subject to the CPP. There are 246 units that make up the affected unit list based on 2012 data for goal calculation. For the 2014 inventory we retain the original list of affected units used for the goal calculation, but also include units that have come online or have retired. The 249 EGUs listed as affected units includes 3 units that are expected to begin operation in 2016, but were not operating in 2014 (the inventory year).

Power Turbine			
Combined Cycle Single Shaft	7	2,250	240 – 405
Total	249	38,015	4 – 806

\*Listed for informational purposes; does not count towards the total.

The age of California’s fleet of affected EGUs ranges from 67 years old to those that have not yet begun operation. The age of affected units is almost evenly split between those that are older than 25 years and those that are younger than 25 years. There are 117 units totaling more the 18,511 MWs, that are more than 25 years old and 132 affected units totaling more than 19,503 MWs that are younger than 25 years old.

#### *Affected EGUs by District*

There are 15 California local air districts that had affected units in 2012. However, due to the shutdown of units (as described above) one district (San Louis Obispo) will no longer have any affected units. South Coast Air Quality Management District has the largest number of units followed by San Joaquin Valley Air Pollution Control District. The statistical makeup of the affected units by District is listed below in Table 3.

**Table 3 – CPP Units and Facilities by Air District**

District	Units	Facilities	MWs
Bay Area AQMD	36	13	6,293
Colusa County APCD	3	1	668
Feather River AQMD	6	3	673
Imperial County APCD	5	1	277
Kern County APCD	2	1	55
Monterey Bay APCD	10	2	2,620
Mojave Desert AQMD	24	12	2,646
Placer County APCD	3	1	200
Sacramento Metro AQMD	10	4	895
South Coast AQMD	73	22	13,038
San Diego County APCD	18	6	2,355
Shasta County AQMD	3	1	114
San Joaquin Valley APCD	46	22	5,189
San Luis Obispo County APCD	4	1	912
Ventura County APCD	6	3	2,079
<b>Total</b>	249	93	38,015 <sup>(1)</sup>
(1) Does not add due to rounding			



## 2.5 CO<sub>2</sub> Emission Inventory

As required by § 60.5740(a)(1), the list of affected units and their associated emissions is included in Appendix A. This emissions data is based on the year 2014 as it is the most recent calendar year for which complete data was available at the time this Proposed Plan was developed. Based on U.S. EPA's 2014 EIA data and using the revised list of affected units, California's affected units emitted a total of 45.3 million short tons (MST) (41.1 million metric tons). The total generation in 2014 was 104,200.7 GWhs. The combined rate for California for 2014 was 870 lbs/MWh. (See Table 4 below)

**Table 4 – 2014 Emissions from Affected Units**

<b>Year</b>	<b>2014</b>
CPP Affected EGU Emissions (MST)	45.3
CPP Affected EGU Generation (MWh)*	98,566,576
CPP Affected EGU UTO (Converted to MWh)**	5,634,180
CPP Affected EGU Total Base Generation (UTO+Gen) (MWh)	104,200,756
CPP Affected EGU Raw Emission Rate (lbCO <sub>2</sub> e/MWh)	870

\*(Uses EPA Rule for modification of generation of certain CHP (cogeneration) units by a 1/0.95 factor)

\*\* (Uses EPA Rule for conversion of the UTO (useful Thermal Output) in units of MWh)

## 3. California CPP GHG Targets

Pursuant to 40 C.F.R. § 60.5745(a)(2), ARB staff has calculated the CO<sub>2</sub> emissions performance goals that affected EGUs must collectively achieve for CPP compliance.

The Clean Power Plan establishes both a rate- and mass-based, state specific CO<sub>2</sub>e limit for the total affected EGU emissions in each state. ARB staff are proposing to use the mass-based limit as it most readily conforms to the mechanism of mass emissions compliance instruments used by the Cap & Trade Program. California adjusted its list of affected EGUs as described above. A further provision, 40 C.F.R. § 60.5855(d), provides that CO<sub>2</sub> emission goals “may be changed...as a result of changes in the inventory of affected EGUs,” with U.S. EPA's approval. Accordingly, ARB staff has recalculated its goals, based on U.S. EPA's methodology, as follows.

The U.S. EPA established default mass limits for each state using a methodology that develops factors applied to each state's generation profile based on the state of the entire national generation system. This makes adjusting the underlying factors, based on changes each state may have to the list of affected units established by the U.S. EPA for them, practically impossible. While the factors themselves cannot be adjusted,

these factors may be applied to an updated list of affected units established by each state.

ARB staff has updated the default list of affected units provided by the U.S. EPA, and using this updated list, the mass limit has also changed. The 2012 base generation and emissions data used by the U.S. EPA as well as the default factors already established to be applied to the affected units remain unchanged in the California update. The only change is to the units included as affected by the rule. Thus, when a new unit has been included as affected, its generation and emissions are specified using same 2012 data provided by the U.S. EPA in its default method. To make the change, the emissions and generation from newly included units are simply changed from excluded to included, just as units that have been excluded are now dropped from the calculation, and the already established spreadsheet model of USEPA does the calculations using this new list of units to generate a new mass limit.

The updated cumulative mass limit for 2022-2029: 423,990,560 short tons of CO<sub>2</sub>e (or 52,998,820 as an annual average) and for 2030-2031: 100,587,722 short tons of CO<sub>2</sub>e (or 50,293,861 as an annual average). This limit represents the cumulative mass emissions allowed for the 8 year period 2022-2029 or the 2 year period 2030-2031. To illustrate how these recalculations affected the limits, average annual limits are displayed below, solely as examples. The examples are constructed by showing the average mass emissions, if emitted each year of the period, that would just meet the limit for that period. A complete spreadsheet showing the recalculation is attached as Appendix C.

Table 5 shows the resulting changes to the full period mass limits:

**Table 5: Full Period Mass Limits: Short Tons CO<sub>2</sub>e (Annual Average)**

<b>Affected Unit List</b>	<b>Interim: 2022-2029</b>	<b>Final: 2030-2031</b>
USEPA Default List	408,216,600 (51,027,075)	96,820,240 (48,410,120)
Updated California List	423,990,560 (52,998,820)	100,587,722 (50,293,861)

#### **4. Description of California’s Proposed CPP Compliance Plan**

Pursuant to 40 C.F.R. §§ 60.5740(a)(2), (3) & 60.5745(a)(1), ARB staff is providing this description of California’s Proposed CPP Compliance Plan.

##### **4.1 Plan Type and Geographic Scope**

ARB is proposing a mass-based, single state, state measures plan that includes emissions standards for affected EGUs, and backstop emission standards. The Proposed Plan is based on California’s Cap-and-Trade Regulation and its supporting Mandatory Reporting Regulation.

## 4.2 Plan Overview: The CPP and the California System

The CPP adds a federal overlay to California's existing, ongoing, GHG emissions control efforts, including the California Cap-and-Trade Program. California has operated an economy-wide Cap-and-Trade system, authorized by the Global Warming Solutions Act of 2006, AB 32, since 2013. A core goal for ARB in developing this Proposed Plan is to integrate the state and federal systems as seamlessly as possible, guaranteeing that federal targets for affected EGUs will be met, while continuing to drive GHG reductions across California's economy. Accordingly, this Proposed Plan is being developed in coordination with the regulatory process developing the next phase of California's Cap-and-Trade Program and Mandatory Reporting Regulation, which are core components of California's suite of climate change regulations.

### *Overview of California Climate Policy*

California has been a leader in addressing greenhouse gases (GHGs) since the passage of Assembly Bill 32 (AB 32), the California Global Warming Solutions Act of 2006 (AB 32, Statutes of 2006, Chapter 488), which represented a defining moment in California's long history of environmental stewardship and secured the State's role as a leader in reducing greenhouse gas (GHG) emissions. California seeks to fight climate change by employing a comprehensive, long-term approach to cut the State's GHG emissions to 1990 levels by 2020 and to maintain and continue reductions post 2020. Since the time the first energy efficiency requirements were adopted, to the Renewable Portfolio Standard (RPS), to the Pavley Advanced Clean Car Standards, and the recent proposed Short Lived Climate Pollutant Strategy, the State has been consistent and bold in its efforts to address climate change and serve as an example of how other regions can take similar action in reducing GHGs.

As required by AB 32, in 2008, the first Climate Change Scoping Plan laid out a comprehensive program to reduce California's GHG emissions to 1990 levels by 2020, to reduce the State's dependence on fossil fuels, to stimulate investment in clean and efficient technologies, and to improve air quality and public health. The coordinated set of policies in the Scoping Plan employed strategies tailored to specific needs, including market-based compliance mechanisms, performance standards, technology requirements, and voluntary reductions. The Scoping Plan described a conceptual design for a cap-and-trade program that included eventual linkage to other cap-and-trade programs to form a larger regional trading program. As implemented, the Cap-and-Trade Program is designed to work in concert with other measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. The Cap-and-Trade Program also complements and supports California's existing efforts to reduce criteria and toxic air pollutants. AB 32 also requires the Scoping Plan to be updated at least once every five years, and the first update was in 2014.

The recently released 2014 GHG inventory demonstrates that the State's suite of climate policies are yielding GHG reductions and the State is on track to achieve the

2020 statewide target and accomplish its longer-term climate goals. The set of actions the state is taking is driving down greenhouse emissions and moving the state towards a cleaner energy economy. Energy efficiency efforts—like new green building standards now in effect for homes and businesses and new standards for appliances, televisions, and other “plug loads”—continue to reduce energy use and emissions and cut energy costs. As renewable energy costs in California have rapidly decreased, the state is making great strides in developing renewable energy, with renewables cost-effective for millions of homes and businesses.

California has also taken innovative actions to cut GHG emissions from the transportation sector. Collectively, the state’s set of vehicle, fuels and land use policies is cutting emissions and drivers’ fuel costs, trends that are expected to continue beyond 2020. California’s Low Carbon Fuel Standard (LCFS) is driving the production of a broader array of cleaner fuels giving California businesses and consumers more choices in the fuels they use. In addition, companies are finding innovative ways to produce cleaner, low carbon fuels. Further, the cars on California’s roads are transforming as a result of GHG standards, which are now federal law, and California’s pioneering zero emission vehicles (ZEV) regulation is expected to lead to significant electrification by 2025. Because electrification will increase demand on the electricity sector, parallel programs to ensure that the electricity sector moves toward cleaner energy, like those discussed above, are important and underway.

Despite California’s marked progress, greater innovation and effort is needed to avoid the worst consequences of climate change. Recognizing the threat to California’s future, Governor Brown called on California to pursue a new and ambitious set of objectives to continue to reduce GHG emissions by 2030 and beyond. In his January 2015 inaugural address, Governor Brown identified five key climate change strategy “pillars,” which recognize that several major areas of the California economy will need to reduce their emissions to meet California’s ambitious climate change goals. These five pillars are:

1. Reducing today’s petroleum use in cars and trucks by up to 50%;
2. Increasing from one-third to 50% our electricity derived from renewable sources;
3. Doubling the efficiency savings achieved at existing buildings and making heating fuels cleaner;
4. Reducing the release of methane, black carbon, and other short lived climate pollutants; and
5. Managing farm and rangelands, forests and wetlands so they can store carbon.

Consistent with these goals, Governor Brown signed Executive Order B-30-15 in April 2015 establishing a California GHG reduction target of 40 percent below 1990 levels by 2030. This new emissions reduction target represents the most aggressive benchmark enacted by any government in North America to reduce GHG emissions over the next decade and a half. This new target is also consistent with the scientifically established levels needed to limit global warming below 2 degrees Celsius (°C)—the warming

threshold at which scientists agree that there will likely be major climate disruptions—and aligns California's GHG reduction targets with those of leading international governments.

Executive Order B-30-15 calls on ARB to update the AB 32 Climate Change Scoping Plan to incorporate the 2030 target. The 2030 Target Draft Scoping Plan will serve as the framework to define the State's climate change priorities for the next 15 years and beyond. The 2030 Target Draft Scoping Plan is expected to be considered by the Board for a final vote in early 2017. It will chart the path to achieving the 2030 target and describe the potential role of a post-2020 Cap-and-Trade Program.

Some of the “pillars” goals are reflected in a new statute, SB 350 (Statutes of 2015, De Leon), which further intensified California's electricity sector decarbonization efforts. Among other measures, the statute expanded renewable procurement requirements for California utilities to 50% or more, embedded greenhouse gas emissions reduction in a new integrated resource planning process for most utilities, set targets for greatly increased energy efficiency, and encourages widespread transportation electrification. It has not yet been fully implemented, but its requirements will be reflected in state policy moving forward.

ARB is proposing to move forward regulatory amendments to the Cap-and-Trade Regulation to extend the program post-2020 and to provide an investment signal that the current suite of climate policies, including the Cap-and-Trade Program, are delivering the reductions needed to achieve the 2020 target and have an essential continued role to play in achieving the 2030 target. This Proposed Plan is built on the recently proposed amendments to the Cap-and-Trade Regulation.

### *The Cap-and-Trade Regulation*

The Cap-and-Trade Regulation, which covers electricity generation and imported power, industrial sector emissions, and produced and imported fuel, is designed to ensure capped sector emissions decline to 1990 levels by 2020, and then to continue and maintain these reductions. (See Health & Safety Code §§ 38550, 38551, 38560, 38562, 38570 (authorizing statutes), and 17 CCR §§ 95800 *et seq.* (codified Cap-and-Trade Regulation). California's Mandatory Reporting Regulation (MRR) tracks emissions throughout the state, including in all covered sectors, and ensures the state Cap-and-Trade Program operates on strong foundation of rigorous and third-party verified GHG emissions data. (See Health & Safety Code §§ 38530, 38562 (authorizing statutes) and 17 CCR §§ 95100 *et seq.* (codified regulation). California's program is linked to the program operating in the Canadian province of Quebec, and further linkages, including to the province of Ontario, are anticipated over the next decade.

### *The Clean Power Plan's State Measures Program Type and the Cap-and-Trade Regulation*

The Cap-and-Trade Program is a core element of California's strategy to achieve the scientifically-necessary climate goals set by AB 32, and by Executive Orders S-3-05

and B-30-15. It is a primary tool to ensure that California meets emissions targets of 1990 levels by 2020, and is being reviewed as part of the Board's consideration of post-2020 climate policy for its suitability to achieve further targets of 40% below 1990 levels by 2030, and 80% below 1990 levels by 2050. In particular, to ensure that the state program, now focused on achieving the 2020 target of 1990 levels, continues to meet state climate goals, ARB is proposing amendments to both the Cap-and-Trade Regulation and MRR.

Among those amendments are provisions intended to allow the state program to also serve as California's compliance mechanism for CPP. U.S. EPA designed the CPP to allow this option. As U.S. EPA explains in the CPP preamble, "a mass-based emission budget trading program with broader source coverage and other flexibility features may be designed such that compliance by affected EGUs... would assure achievement of the applicable state mass-based CO<sub>2</sub> goal," but these systems, given their flexibility measures (such as offsets) and larger scope, "must be submitted as a part of a state measures plan type." (80 Fed. Reg. at 64,891).

Under a state measures plan, certain requirements that apply solely to affected EGUs would become federally-enforceable emission standards. These include "the requirement for an affected EGU to surrender emissions allowances equal to reported CO<sub>2</sub> emissions, and meet monitoring and reporting requirements." (*Id.*) However, the state regulation in which these requirements exist is submitted only as "supporting documentation" and does not become federally enforceable more broadly. Other sources covered by the state program are not covered by federally-enforceable requirements. As a result, the larger state Program – including affected EGUs – continues to operate as an integrated system, rather than requiring a separate CPP-only system for the affected EGUs.

To ensure emissions reductions required of affected EGUs are met, states using this approach are also required to include a federally-enforceable "backstop" set of emission standards that apply if affected EGU emissions exceed federal targets. The backstop must be designed to reduce reported stack emissions from affected EGUs to the required target level, as well as to recoup any emissions overage. (See 80 Fed. Reg. at 64,891-92, 40 C.F.R. § 60.5740).

U.S. EPA is clear that this plan type is available only to states that can demonstrate that their combination of state measures and emission standards will meet CPP targets. California's demonstration, detailed extensively below, shows that California's system is expected to meet and exceed federal target levels for affected EGU emissions. Accordingly, a state measures plan design is available to California.

Staff proposes this design because it has very significant advantages for affected entities. This approach maintains the efficient and effective California Cap-and-Trade Program, without isolating affected EGUs in a CPP-only system. It therefore supports a system now yielding emissions reductions in the state, and with California's linked partners. Although CPP requirements necessitate certain changes to the California

program (discussed below), the state measures plan type broadly allows for integrating the state and federal systems without unduly disrupting the efficient system now in place.

Over time, if California's system continues to expand, or if the states complying with CPP opt to develop their own trading programs, an integrated system can also support broader linkages. California actively pursues collaborative climate policy efforts with many jurisdictions, and ARB staff anticipates that as other states develop CPP plans, including market-based plans, these plans will be carefully evaluated for potential connections with California policies.

#### 4.2.1 Detailed Summary of California's Cap-and-Trade Regulation

The Cap-and-Trade Regulation, as authorized by AB 32, is a mass-based trading system whose purpose is to achieve and maintain California's emission targets by applying a declining aggregate greenhouse gas allowance budget on covered entities and providing a trading mechanism for compliance instruments. (17 CCR § 95801).<sup>7</sup> This section highlights key features of the Regulation, proposed to persist in their fundamentals into the CPP compliance period, as they relate to CPP affected EGUs. Proposed amendments to the Regulation addressing further CPP requirements are discussed in a later section of this Proposed Plan.

##### *California's Statewide Greenhouse Gas Emissions Limit*

Among other requirements, AB 32 directed ARB to restore California statewide GHG emissions to 1990 levels by 2020. (Health & Safety Code §§ 38551, 38550). The annual allowance budget, or cap, is set to assure that California meets its emission targets under AB 32, and related Executive Orders. (See Health & Safety Code §§38550, 38551, 38570). California compliance instruments are created by ARB, and issued according to an annual allowance budget. (17 CCR § 95820).

The Regulation's allowance budgets are established through December 31, 2020, and decline at a rate of about 3% annually. Compliance with the Regulation assures that the aggregate GHG emissions decline in accordance with the cap decline factor, to assure that California, as a whole, meets its emissions targets.

##### *Coverage, Compliance Obligations, and Other Core Requirements*

The Cap-and-Trade Regulation addresses emissions of CO<sub>2</sub>, along with several other GHGs, from sources comprising approximately 85% of California's emissions. (See 17 CCR §§ 95810, 95811). In the electricity sector, electrical generating facilities (both

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<sup>7</sup> Extensive information on the Regulation and the carbon market is available at ARB's webpage for the program, <http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm>. The development documents for the initially-adopted regulation in 2010 (available at: <http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm>) provide a detailed overview of many core design decisions within the Regulation.

new and existing) and electricity importers are covered. (17 CCR § 95811(b)(1)-(2)).<sup>8</sup> Both sets of electricity generating facilities are covered if annual emissions are at or above 25,000 metric tons CO<sub>2</sub>e in a given year. (17 CCR § 95812(c)). Once an entity is covered, it remains covered until the compliance period *after* its emissions are either below the coverage threshold for “one entire compliance period” or it has shut down all operations subject to reporting. (17 CCR § 95812(e)).<sup>9</sup> Covered entities must report and verify their emissions consistent with the Mandatory Reporting Regulation discussed in more detail below.

Owners and operators of covered units must register with ARB, and designate qualified representatives to act for them. Entities in the market are subject to extensive review and monitoring requirements conducted by ARB’s Market Monitoring Unit. (See *generally* 17 CCR Article 5, Subart. 5).

Covered entities in the Cap-and-Trade Program are responsible for acquiring and surrendering compliance instruments equal to their covered emissions. (17 CCR § 95850). These obligations apply for every verified metric ton of CO<sub>2</sub>e.<sup>10</sup> (17 CCR § 95852(a)(1)).<sup>11</sup> Obligations are assessed at the facility level. (*Id.*).

Covered entities must surrender one compliance instrument for each metric ton of CO<sub>2</sub>e in their compliance obligations, and have both annual and triennial compliance obligations. (17 CCR § 95856(a)). Annually, entities must surrender emissions equal to one-third of their emissions from the previous data year (17 CCR § 95855), and after the conclusion of each multi-year compliance period, entities must surrender compliance instruments sufficient to cover all remaining emissions for the period (17 CCR § 95856(d)).

Covered entities may acquire compliance instruments (issued either by ARB or a linked market partner) in several ways. ARB holds regular auctions for allowances (including a separate auction for future vintages), conducting auctions jointly with its current linked partner, Quebec.<sup>12</sup> (See 17 CCR §§ 95910-95914). Parties also have the option, under some circumstances, of purchasing allowances from the Allowance Price Containment Reserve (APCR), a pool of vintage-less allowances maintained by ARB designed to constrain allowance prices if necessary. (See 17 CCR 95913). Entities may also trade amongst themselves in the secondary market to acquire or exchange compliance

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<sup>8</sup> A “facility” for purposes of the Cap-and-Trade Regulation is “any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties... that emits or may emit any greenhouse gas.” (17 CCR §95802(a)(144)(A)). Accordingly, one electrical generating facility may include several EGUs. (See 17 CCR § 95802(a)(121)).

<sup>9</sup> As discussed below, ARB is proposing amendments to ensure that CPP EGUs remain covered even if they otherwise meet cessation criteria.

<sup>10</sup> Emissions from certain biogenic sources do not have a compliance obligation. (17 CCR § 95852.2).

<sup>11</sup> In certain rare instances, ARB may also assign emissions levels (and hence compliance obligations) based on available information to address instances of noncompliance with reporting and verification requirements.

<sup>12</sup> Linkage is discussed in more detail below.



instruments. (See 17 CCR §§ 95921-95923). Entities may bank allowances indefinitely. (17 CCR § 95922).

Certain entities within the market may also be allocated free allowances, including electrical distribution utilities<sup>13</sup> and industrial entities receiving transition assistance into the program or assistance to prevent emission leakage. (See *generally* 95870-95895). Electrical generating facilities, as defined by the Cap-and-Trade Regulation do *not* receive allocation. However, industrial co-generation facilities are eligible for allocation, if all requirements are met.<sup>14</sup>

Entities are also authorized to use a limited number of “offsets.” (See 17 CCR Article 5, Subart. 13). Offset projects must be registered with ARB, and produce offset credits only if emission reductions from the project are real, quantifiable, additional, permanent, verifiable, and enforceable. (17 CCR 95970(a)(1)). ARB staff rigorously review offset projects, and have established a limited number of offset protocols that define categories of acceptable projects. (See 17 CCR § 95972). Only registered projects operating under these protocols (or those of ARB’s linked partners), and confirmed by third-party verification, may generate compliance offsets. (See 17 CCR § 95981). An entity may use compliance offsets to fulfill no more than 8% of its compliance obligation. (See 17 CCR § 95854).<sup>15</sup>

### *Compliance Periods and Surrender Timing*

The Cap-and-Trade Regulation’s requirements are designed to ensure that the approximately 450 covered entities have sufficient time to report and verify emissions, ARB has sufficient time to determine reliable compliance obligations, and compliance instrument surrender occurs simultaneously for covered entities. These requirements are important to ensuring that the program, which covers a wide range of sources, operates smoothly, with reliable data, and with liquid markets for entities engaging in trading and auctions, as well as to ensure smooth operations with linked programs.

The Regulation began with a two-year compliance period on January 1, 2013; from January 1, 2015 forward, two three-year compliance periods bring the Program to December 21, 2020. (17 CCR § 95840). Multi-year compliance periods have been deemed necessary to support liquidity and to address potential variations in emissions from the power sector, which may occur, for instance, due to year-to-year variation in hydroelectricity generation.

Compliance instrument surrender is required each November 1, for the annual compliance obligation for the prior year, and the November 1 following each compliance

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<sup>13</sup> The utilities are required to monetize their allocated allowances and to use the proceeds to benefit retail ratepayers. (See 17 CCR 95892).

<sup>14</sup> As noted below, this is an issue for a single CPP affected EGU, which California defines as an industrial cogeneration facility.

<sup>15</sup> U.S. EPA is clear that programs that include offsets may satisfy CPP requirements, so long as they include a rigorous federal backstop. (See, e.g., 80 Fed. Reg. at 64,891).

period for the full compliance period obligation. (17 CCR § 95856(d) & (f)). Untimely surrender incurs a quadruple compliance instrument surrender obligation, with three-quarters of this increased obligation fulfilled by allowances (offsets may be used for the remainder, although the 8% limit continues to apply). (See 17 CCR § 95857). Compliance instruments surplus to the covered emissions of the late entity are then returned to the market.

### *Linkage*

State law authorizes California to link its Cap-and-Trade Regulation to other trading programs, if certain conditions are met. (See Government Code § 12894).

Senate Bill 1018 (SB 1018; Chapter 39, Statutes of 2012) requires that the Governor of California make four findings prior to linking the California Program with other jurisdictions to enable the use of compliance instruments (allowances or offset credits) issued by other jurisdictions for use in California's Program. (Gov. Code, § 12894(f).) Under SB 1018, the Governor must find that:

- The linked program has adopted program requirements for greenhouse gas reductions; including, but not limited to, requirements for offsets; that are equivalent to or stricter than those required by AB 32;
- The State of California is able to enforce AB 32 and related statutes against any entity subject to regulation under those statutes, and against any entity located within the linking jurisdiction to the maximum extent permitted under the United States and California Constitutions;
- The proposed linkage provides for enforcement of applicable laws by the linking jurisdiction of program requirements that are equivalent to or stricter than those required by AB 32; and
- The proposed linkage shall not impose any significant liability on the State or any State agency for any failure associated with the linkage.

In 2014, Governor Brown made these four findings for linkage with Québec, confirming the relative stringency of the California and Québec programs.<sup>16</sup> This means that allowances and offsets issued by Quebec may be used for compliance with the California regulation, and the same is true for California compliance instruments in the Quebec system. (17 CCR § 95942).

ARB continues to investigate linkages with other cap-and-trade systems. If other states develop and implement cap-and-trade programs to comply with the CPP, or their own policy goals, linkages with those programs could be considered in the future if they meet linkage requirements.

### *Pending Amendments to the California Cap-and-Trade Regulation*

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<sup>16</sup> <http://www.arb.ca.gov/cc/capandtrade/linkage/linkage.htm>

In addition to CPP-related amendments described below, ARB is currently proposing a series of amendments to the Cap-and-Trade Regulation to further strengthen the system. ARB believes that these amendments, if approved, will further strengthen California's climate policy, and CPP compliance. Critical features of the proposed amendments include tightened overall emissions caps through 2050, consistent with an 80% overall reduction in economy-wide emissions from 1990 levels by 2050. This would result in a statewide emission level of 200.5 MMT CO<sub>2</sub>e for entities in the Cap-and-Trade Program by 2030, and of 66.5 MMT CO<sub>2</sub>e in 2050. The proposed amendments also include program linkage with the Province of Ontario's program in 2018, many measures to further improve the rigor and accuracy of the program (including with regard to electricity imports), and measures to further address emissions leakage. A full description of the proposed amendments is available on ARB's website, with complete text and analysis of the proposed changes. Although ARB believes these amendments will increase the rigor of the program, and bolster CPP compliance, staff will carefully review any potential interactions between this proposed Plan and the amendments before finalization of the Plan and of the proposed regulations. Both the regulation and the Plan are expected to be heard by the Board for finalization in spring 2017.

#### 4.2.2 Overview of California's Mandatory Reporting Regulation

The core data used to implement the Cap-and-Trade Regulation is provided by ARB's Mandatory Reporting Regulation. Also authorized by AB 32 (see, e.g., Health & Safety Code § 38530), MRR is designed to provide a consistent source of rigorous, third-party verified data for many of ARB's programs. It encompasses all CPP-affected EGUs. MRR uses U.S. EPA's reporting regulations as a basis for many of its requirements, but extends these requirements to provide the additional data and rigor required to support the Cap-and-Trade Program.

MRR requires the largest GHG emitters serving California to annually report GHG emissions to ARB. (17 CCR § 95101). It includes all EGUs that are already reporting CO<sub>2</sub> mass emissions to U.S. EPA under the 40 C.F.R. Part 75 Acid Rain Program, regardless of emission level. (17 CCR § 95101(a)(1)(A)(1)). All stationary combustion units, including industrial cogeneration facilities, with emissions over 10,000 metric tons CO<sub>2</sub>e are also included. (17 CCR § 95101(a)(1)(B)(1)).<sup>17</sup> Reporting occurs at the facility level, using the facility definitions also used by the Cap-and-Trade Regulation. Reporters must remain in MRR as long as they are covered by the Cap-and-Trade Regulation, until emissions drop below 10,000 metric tons for three consecutive years, or until they shut down completely. (17 CCR § 95101(h)).

All reporters with Cap-and-Trade Program compliance obligations (including all those with emissions over 25,000 metric tons CO<sub>2</sub>e annually) must obtain third-party verification services. (17 CCR § 95103(f)). Verification includes a careful and rigorous data review by an independent verifier, accredited by ARB. A positive or qualified

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<sup>17</sup> Electricity importers also have reporting and verification obligations.

positive verification statement<sup>18</sup> indicates the verifiers' determination that the emissions data report is free of material misstatements. (17 CCR § 95131(c)(3)(C)).<sup>19</sup>

Reporting for stationary sources, including affected EGUs, is required by April 10 of each calendar year. (17 CCR § 95103(e)). Verification begins after reporting, and a verification report must be submitted by September 1 of each year. (17 CCR § 95103(f)).

Reporting requirements for EGUs are contained in section 95112 of MRR (17 CCR § 95112), which builds directly on the federal GHG Reporting Rule, 40 C.F.R. Part 98; that rule, in turn, is based heavily on Acid Rain Program reporting requirements contained in 40 C.F.R. Part 75. (See 17 CCR § 95112). Covered facilities report CO<sub>2</sub> emissions, along with information on generated electricity and disposition of thermal energy (for cogeneration units). (17 CCR § 95112(a)(4) & (5)). MRR generally collects this information at the facility level, but operational information on individual EGUs is also required. (17 CCR § 95112(b)).

MRR entities subject to the Cap-and-Trade Regulation are required to maintain records sufficient to allow for verification for ten years from the date each emission report is certified. (17 CCR § 95105). These reporters also prepare and submit detailed GHG Monitoring Plans that outline their reporting approach. (17 CCR § 95105(c)). Other records must be made available to ARB within twenty days of an ARB request. (17 CCR § 95105(b)).

### *Proposed Amendments to the Mandatory Reporting Regulation*

As well as the CPP-related amendments described below, ARB is currently proposing to amend the Mandatory Reporting Regulation in various regards. These amendments generally improve the quality and accuracy of reported information, and do not affect CPP EGUs in any way that would diminish the accuracy of required CPP reporting. The proposed amendments also include moving the verification deadline from September 1 each year to August 1. A full description of MRR amendments can be found on ARB's website. As with proposed amendments to the Cap-and-Trade Regulation, any potential interactions with CPP compliance will be carefully considered before finalization of the Plan and of the proposed regulations. Both the regulation and the Plan are expected to be heard by the Board for finalization in spring 2017.

#### 4.3 Proposed Amendments Aligning California's Regulations with the CPP

California's Cap-and-Trade Regulation and MRR provide a well-developed foundation upon which to build the federal CPP requirements that apply to a subset of the sources

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<sup>18</sup> Qualified positive verification reports are for emissions reports free of material misstatement that the verifier believe contain some nonconformances with MRR.

<sup>19</sup> In cases where an entity receives an adverse verification statement, or fails to report, ARB may assign an emissions level based on a thorough analysis. (See 17 CCR § 95131(c)(5)).

covered by the state regulations. Because the state and federal systems vary in their coverage and approach, a limited number of amendments are required to integrate the two systems. ARB is proposing this Proposed Plan in coordination with an array of amendments to both state regulations intended to assure CPP compliance. As discussed above, ARB is proposing other amendments to both state regulations to prepare for coming state compliance periods and the post-2020 period.

For CPP purposes, several amendments are important to highlight, and are discussed in detail below.

Proposed Cap-and-Trade amendments, in addition to broader, state-level amendments, needed to extend and strengthen the program for the post-2020 period, include:

- Requirements for all CPP affected EGUs to participate in the Cap-and-Trade Program.
- Alignment of Program compliance periods with CPP compliance periods, including a bridge period to link the two programs.
- Provisions setting interim mass targets and final mass targets for affected EGU emissions.
- Provisions establishing federally-enforceable backstop emissions standards.

Proposed MRR amendments include:

- Requirements for all CPP affected EGUs to report and verify emissions, regardless of emission level.
- Requirements for reporting to be conducted consistent with CPP requirements.
- Requirements for recordkeeping consistent with CPP requirements.

Each of these amendments is discussed below. The discussion also describes how these requirements relate to CPP standards for mass-based trading programs generally.

The CPP-related amendments to both regulations are largely contained in separately-identified portions of the regulations. This approach makes them easy to identify for stakeholders, and also allows ARB to clearly specify which portions of the regulations are identified as federally-enforceable emission standards, as opposed to state measures. A table of amendments and measures appears in section 4.5

#### 4.3.1 Provisions to Include Affected EGUs

The CPP applies to all affected EGUs regardless of emission level, because CPP applicability is determined by unit operating characteristics. Accordingly, ARB staff is proposing amendments to make clear that all CPP-affected EGUs must continue to participate in the Cap-and-Trade and Mandatory Regulations unless they completely close and shut down.

This is already largely the case for the MRR, which requires EGUs that are covered by U.S. EPA's Part 75 to report regardless of emissions level (See 17 CCR § 95101(a)(1)(A)1.) but, to avoid any confusion as to non-Part 75 units or cogeneration or other industrial units that may be included in the CPP's affected EGU definition, staff are proposing limited MRR amendments to make clear that reporting and verification must continue for affected EGUs, at the unit level, unless they undergo a complete and permanent shutdown, with a full cessation of all emitting processes.

The Cap-and-Trade Regulation currently imposes a compliance obligation upon electrical generators that emit more than 25,000 tons CO<sub>2</sub>e annually. (17 CCR § 95812(c)(2)(A)). To ensure that this requirement applies at the unit level, per the CPP, and continues to apply regardless of emission level, ARB staff is proposing amendments to that effect.

#### 4.3.2 Compliance Period Changes

ARB staff is proposing to amend compliance periods for the Cap-and-Trade Regulation to better align with the CPP. The Cap-and-Trade Regulation's compliance periods are set through December 31, 2020. (17 CCR § 95840). They consist of one two-year compliance period from January 1, 2013 to December 31, 2014, followed by two three-year compliance periods.

Multi-year compliance periods, and three-year periods in particular, were selected to address challenges that might otherwise be driven by interannual variability in the economy and, especially, in electric power supply and demand. Because a large portion of California's power is supplied by hydroelectricity, and the West is prone to drought and flood years, variability here is especially important to account for. After an extended stakeholder process, the three-year compliance periods were implemented in order to manage these challenges.

The CPP, however, requires some changes to this approach. Specifically, 40 C.F.R. § 60.5770(b)(3) and (b)(4) require that both emissions standards and state measures employed for CPP compliance purposes must operate on the same schedule as the CPP, including during interim compliance steps.<sup>20</sup> More specifically, though states may subdivide the CPP's compliance periods (40 C.F.R. § 60.5770(c)(3)), they may not extend them.

The CPP sets out three interim "steps" within the interim "period" from 2022 to 2029: January 1, 2022-December 31, 2024, January 1, 2025-December 31, 2027, and January 1, 2028-December 31, 2029. (40 C.F.R. § 60.5880). A final period follows, broken into two-year reporting periods, beginning with January 1, 2030-December 31, 2031. (*Id.*).

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<sup>20</sup> The CPP uses interim "period" to refer to the entire time between 2022 and 2029, and interim "steps" to refer to divisions within this time. (40 C.F.R. § 60.5880).

ARB staff is proposing to align the Cap-and-Trade Regulation with these interim steps and final reporting periods by dividing the program’s compliance periods as follows after 2020:

- January 1, 2021 – December 31, 2022 (“bridge” period);
- January 1, 2023 – December 31, 2024 (remainder of first CPP interim step);
- January 1, 2025 – December 31, 2027 (second CPP interim step);
- January 1, 2028 – December 31, 2029 (third CPP interim step); and
- January 1, 2030 – December 31, 2031, and every two years thereafter (final CPP reporting periods).

This proposed timing ensures that each compliance period is at least two years long, to continue to account for the interannual variability that ARB has designed the current Cap-and-Trade Program to address (albeit with two-year periods for the most part, rather than three).

Under this proposal, the first CPP interim step is divided into two periods, as is permitted (40 C.F.R. § 60.5770(b)(3)), with the first year of the CPP interim step joined to a “bridge” period that also includes the 2021 calendar year. This avoids creating an “orphan” year between the end of the 2018-2020 compliance period in the California Cap-and-Trade Regulation and the beginning of the CPP compliance period.

During the bridge period, affected EGUs will have obligations, as a matter of state law, for all covered emissions during both 2021 and 2022. However, only obligations as to 2022 calendar year emissions will be federally enforceable. Affected EGUs may comply with their obligations using compliance instruments issued in or before the bridge period, as is permissible under both state law and the CPP, both of which allow for banking of compliance instruments. (See 40 C.F.R. § 60.5815(e), 17 CCR § 95922), This means that the federalized portion of the compliance period begins only as of the first CPP interim step, bringing the programs into alignment while avoiding issues associated with interannual variability to the extent possible.

#### 4.3.3 Interim Targets

The CPP allows states to develop their own interim step goals and final reporting period goals for affected EGUs provided, for mass-based plans, that the goals cumulatively meet CPP requirements. (40 C.F.R. § 60.5855(c)). As discussed above, ARB staff has also recalculated the *total* mass requirements for the interim and final periods; the interim targets are based upon those recalculated values. The proposed targets are as follows, expressed in metric tons for consistency with the California system. To be clear: The “annual CPP glidepath targets” for 2022-2029 sum to the federal target for the interim period (as recalculated by ARB based on the updated list of affected EGUs). They are illustrative of expected emissions in each year of a given compliance period, and are not required values – though their summed values in the “full federal compliance period” target columns will be required, as the target for each compliance period. However, the backstop will only be triggered if affected EGU emissions for an

entire compliance period exceed the backstop “trigger” by 10% of more – a value given in the last column of the table. The targets for the 2030-31 period will repeat for each subsequent compliance period. Note that the federally enforceable targets begin in 2022, though the state-level compliance period begins in 2021, to allow for continuity from the state compliance period ending in 2020.

**Table 6 – Compliance Period Target Values (metric tons)**

Year	Compliance Period	Annual CPP Glidepath Target (MMTCO <sub>2e</sub> )	Full Federal Compliance Period CPP Glidepath Target (MMTCO <sub>2e</sub> )	CPP Backstop Trigger – 10% Above Target (MMTCO <sub>2e</sub> )
2021	4	N/A	50.0	55
2022		50.0		
2023	5	49.4	98.3	108.2
2024		48.9		
2025	6	48.4	143.4	157.8
2026		47.8		
2027		47.3		
2028	7	46.7	92.9	102.2
2029		46.2		
2030	8	45.6	91.3	100.4
2031		45.6		

For all two-year compliance periods after 2031, the CPP Glidepath Target is 91.3 MMTCO<sub>2e</sub> and the CPP Backstop Trigger is 100.4 MMTCO<sub>2e</sub>.

#### 4.3.4 Timing of Reporting, Verification, and Surrender Events

The reporting, verification, and compliance instrument surrender deadlines of the Cap-and-Trade Regulation and MRR within each compliance period (and CPP interim step) will be aligned for affected EGUs and non-CPP entities. To wit, affected EGUs, like all other industrial sources, will report their greenhouse gas emissions, and other required data, to ARB no later than April 10 of each calendar year, and verify these reports by September 1 of each year (see 17 CCR § 95103(e) and (f)),<sup>21</sup> and shall surrender compliance instruments as required by November 1, with regard to both interannual surrenders and to final compliance period surrenders (now referred to as triennial compliance obligations, though this term will change as compliance periods shift to predominantly two-year lengths). (See 17 CCR § 95856(d) & (f)).

<sup>21</sup> In MRR proposed amendments, ARB is proposing to move this date forward to August 1.



Maintaining this basic schedule is critical to maintaining the economy-wide reporting and Cap-and-Trade programs now operating in California and linked jurisdictions, including Quebec. ARB appreciates U.S. EPA's acknowledgement that such programs may be used for CPP compliance (see, e.g., 80 Fed. Reg. at 64,891), and has endeavored to make changes required by the CPP while avoiding, to the extent possible, disturbing critical elements of the larger multi-sector program.

Third-party verification is necessary to ensure that emissions and product data gathered from a wide range of industrial categories is properly reported, consistent with shared accuracy requirements and in conformance with all regulatory requirements. Verification, in turn, requires time after reporting has been initially completed. Although ARB staff is exploring efforts to somewhat shorten the verification calendar, a substantial verification period is essential to data quality sufficient to support the Cap-and-Trade program, along with other ARB programs.

Similarly, it is critical to the Cap-and-Trade Program that all participating entities engage in reporting and compliance on the same timeline. This ensures that market-sensitive information – which includes, critically, each participant's calculated compliance obligation – is released to all parties on a shared schedule. This, in turn, ensures that market demands are known at the same time throughout the market, helping to reduce the risk of market manipulation. It ensures that all market participants face the same compliance requirements to ensure equitable treatment in a market.

For these reasons, ARB is proposing to continue the reporting and verification structure that is operating successfully. This reporting and verification system is significantly more rigorous than the CPP requires, but is appropriate in ARB staff's view, to the operation of a multi-sector Cap-and-Trade program. Accordingly, balancing CPP requirements with the needs of the state program has been an important consideration in designing this Proposed Plan. For instance, ARB is proposing to retain the verification requirements even though they are not required by the CPP while proposing to shift Cap-and-Trade compliance periods, despite concerns over interannual variability, to accord with CPP requirements.

#### 4.3.5 Reporting and Recordkeeping Requirements

The CPP requires states require recordkeeping and reporting from affected EGUs that is "no less stringent" than those set forth in 40 C.F.R. § 60.5860. In many regards, ARB's MRR is already substantially more stringent than the federal reporting programs upon which the CPP is based. Because it supports the Cap-and-Trade program, MRR requires third-party verification and has been carefully amended to build upon federal requirements. However, to further align MRR with the CPP's requirements, ARB staff is proposing amendments to ensure congruent and appropriate reporting program coverage.

The proposed amendments, first, require reporting with regard to each affected EGU (with aggregated reporting permitted in cases where EGUs share a common stack, per

40 C.F.R. § 60.5860(a)(8)), and that reporting and verification are required for all affected EGUs, regardless of emission level. Under the proposed amendments, in addition to completing facility-level reporting under MRR, affected EGUs would also submit specific reports calculated in accordance with all relevant CPP requirements.

These requirements include a requirement to report mass emissions from each EGU as is specified in 40 C.F.R. § 60.5860(b)(1)-(2). EGUs must also submit required net electric output, useful thermal output, and net energy output as is required by 40 C.F.R. § 60.5860(b)(3). Recordkeeping consistent with the CPP, including a requirement that records be retained for at least five years following each compliance period and onsite for at least two years. (See 40 C.F.R. § 60.5860(c)). All relevant CPP reporting and data requirements are reflected in these and related amendments. Reporting under the CPP-only provisions of MRR is to begin for the 2021 data year, in order to provide a full, cross-comparable data set of emissions for the bridge period that leads into the CPP interim steps beginning in 2022.

Reporting is generally required on an annual basis, with verification, consistent with other MRR requirements. Annual reporting will help provide ARB and U.S. EPA with clear and consistent information on compliance, and will also provide an early warning if emissions are approaching backstop trigger levels.

Reporting of compliance-period-long emissions figures and related data is also required at the end of each compliance period (i.e., CPP “interim step”). This reporting includes reports of annual emissions, and compliance period total emissions, per 40 C.F.R. §§ 60.5860(d)(1) and (d)(3). U.S. EPA requires this reporting to be submitted “at the end of each compliance period” (40 C.F.R. § 60.5860(d)); because emissions data for the final year of a compliance period will not be available until after that year. ARB staff understand this requirement to be fulfilled by reporting this data on the regular schedule after the compliance period has ended.

Several CPP reporting requirements, including several intended for the end of the compliance period, are not incorporated into MRR, but are accounted for in other ways. Some are unnecessary for compliance and others are fulfilled by requirements of the Cap-and-Trade Regulation.

Unnecessary requirements include those related to rate-based state plans. Staff are not proposing to incorporate reporting requirements related to rate-based compliance, including Emission Rate Credits (ERCs), because California is proposing to comply with a mass-based strategy.

Requirements addressed in the Cap-and-Trade Regulation include two requirements, 40 C.F.R. § 60.5840(d)(4) & (6), that would require affected EGUs to identify applicable emission standards in their reports and identify the serial numbers of compliance instruments used to comply. These requirements are instead met by the required surrenders during and at the end of Cap-and-Trade Regulation compliance periods (see 17 CCR §§ 95855-57). During surrender events, affected EGUs will be required to

identify, and surrender, compliance instruments sufficient to cover their emissions (including during compliance events for which the backstop standards have been triggered). This process provides the core information required by the CPP, but avoids inserting surrender events into MRR's separate emissions reporting system. By its nature, the Cap-and-Trade Program reconciles emissions for which a compliance obligation attaches to compliance instruments during a surrender event, and so meets this CPP requirement. Accordingly, the combination of MRR reporting and the allowance tracking system supporting Cap-and-Trade (described in more detail below) collect all relevant information, and will support compliance reporting by affected EGUs and by ARB.

#### 4.3.6 Backstop Provisions

ARB and the interagency working group conducted extensive modeling, described in more detail later in this Proposed Plan, showing that it is extraordinarily unlikely that backstop provisions will be triggered. Projected affected EGU emissions are well below – and in many cases over ten million short tons below – federal targets even under relatively conservative projection scenarios. This is true even under stress scenarios under which existing EGUs operate far more than is likely under California's suite of policies. This means that the economy-wide Cap-and-Trade Program will continue to function without a backstop program, even as CPP compliance is assured, just as U.S. EPA envisions (see, e.g., 40 Fed. Reg. at 64,891). However, a set of backstop emission standards is nonetheless important to provide U.S. EPA with assurance that CPP emission targets will be met, and is a required element of a state measures plan (see 40 C.F.R. § 60.5740(a)(3)).

ARB staff propose a backstop emission standard that will minimize disruptions to the economy-wide Cap-and-Trade Program, while ensuring that affected EGU emissions return to the federal target level (less any overage in prior compliance periods) on the required schedule. The backstop is designed as a trading program that would be activated only upon a triggering event. It would work as follows:

- All required triggers for the backstop would be incorporated into the Cap-and-Trade Regulation, along with the relevant interim step and final reporting period CPP target.
- ARB would receive annual emission reports allowing it to determine if the targets have been exceeded by more than 10%, triggering the backstop.
- If a triggering event occurs, and is documented in reported emissions as of the April reporting date for EGUs after a compliance period, ARB would deem the backstop triggered and inform U.S. EPA of the trigger as of the required July state report (see 40 C.F.R. § 60.5870(b)).
- ARB staff would calculate the emissions reductions needed to bring emissions back to the federal targets, and make up any overage tons, on

the basis of verified data submitted by the verification deadline. This information would be used to determine the pool of California CPP Allowances that would be created and used to populate a backstop allowance pool available only to California's affected EGUs, accessible by autumn of the year that the backstop is triggered and U.S. EPA is notified.

- Affected EGUs would be distributed initial allocations of these CPP allowances on the basis of historical operations, based on the ratio of a given EGU's emissions in the compliance period to the emissions of the affected EGUs as a whole over the period. Affected EGUs would be allowed to trade backstop allowances amongst themselves. ARB would not auction allowances for this purpose.
- Each affected EGU would be required to retire backstop allowances for each ton of CO<sub>2</sub> emitted during the backstop compliance period. The total amount of backstop allowances acts as a limit on affected EGU emissions. Any emissions not covered by a backstop allowance would be violations of the program.

During this time, affected EGUs would also continue to participate in the overall economy-wide Cap-and-Trade Program, and so would be required to acquire and surrender compliance instruments in that program as well. However, the requirement to match all emissions with CPP Allowances ensures the affected EGUs do not exceed the federal target levels.

The backstop feature is designed to restore affected EGU emissions to the federal target level within 18 months, including any overage in emissions from the prior compliance period, per the CPP's requirements. Once progress had been restored, the backstop pool would be closed, and affected EGUs would again participate without this additional requirement in California's broader Cap-and-Trade Program.

#### 4.3.7 State Reports

The CPP requires covered states to file regular reports with U.S. EPA, and additional reporting requirements apply to states employing "state measures" plans, as California proposes to do.

Although it is not necessary to include state reporting requirements in the regulatory text ARB staff is proposing, ARB commits to file these required reports. This section identifies the reporting plan per 40 C.F.R. § 60.5740(a)(5). An initial update report, compliance period reports, and an annual state update report are required.

First, the CPP requires ARB to submit an initial progress report to U.S. EPA by July 1, 2021, demonstrating that the state is on track to meet any programmatic milestone steps (such as confirming that all required regulations are in place). ARB commits to submitting this report by the due date.

Second, ARB is required to file a report covering each interim step and each final reporting period as of July 1 in the year following each period. (40 C.F.R. § 60.5870(b)). ARB is committed to providing these regular compliance period reports, updated as appropriate. ARB will provide U.S. EPA with a full account of affected EGU emissions and compliance as of July of the year following each compliance period, including – critically – information on whether the backstop has been triggered. Because the verification cycle and surrender events for the multi-sector Cap-and-Trade Program requires verification events in early autumn and final compliance instrument surrender in late autumn, ARB will track these events and file supplemental reports as needed to inform U.S. EPA of any further developments, including providing a final confirmation that affected EGUs have complied with remaining compliance instrument surrender requirements.

The compliance period reports, and supplemental reports if any, will contain information on the emissions of affected EGUs during each period, and an identification of whether affected EGUs are in compliance with the relevant emission standards. Consistent with the July 1 reporting requirement, by that date affected EGUs will have reported and verified emissions for the prior years of each compliance period, and will have reported emissions for the most recent year, with those reports undergoing verification. All past compliance instrument surrender events can also be accounted for at this time. Any necessary backstop triggering decisions can therefore be made by July of each year, with any report adjustments needed in response to verification, or the autumn surrender events, reflected in supplemental reports as needed.

Finally, there is a separate required annual status report on July 1 of each calendar year (starting in 2022) on the implementation status of all enforceable standards and state measures. ARB commits to making this report. The report will allow a regular opportunity to update U.S. EPA on the status of these programs.

#### 4.4 Specific Identification of CPP Emission Standards and State Measures

Consistent with 40 C.F.R. § 60.5740(a)(2) & (3)'s requirements to identify all emissions standards and state measures, ARB staff propose to identify the following requirements as elements of the Proposed Plan.<sup>22</sup>

The emission standards in the Plan are divided into two groups: emission standards that apply at all times, and emission standards that apply only when the backstop standards have been triggered and are in force. Standards that apply at all times are:

- A requirement that the owners and operators of all affected EGUs maintain compliance with relevant portions of MRR and the Cap-and-Trade Regulation with regard to each affected EGU.

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<sup>22</sup> We note that the regulations are drafted so that CPP-specific requirements will be effective only upon U.S. EPA's approval of this Proposed Plan, in order to avoid imposing any requirements that are not ultimately part of California's approved Plan.

- A specific requirement that owners and operators of affected EGUs surrender one compliance instrument for each ton of greenhouse gas emissions from each affected EGUs on the compliance schedule laid out in the Cap-and-Trade Regulation

Standards that apply only when the backstop requirement is in force:

- A requirement that the owners and operators of all affected EGUs, in addition to maintaining compliance with MRR and the Cap-and-Trade Regulation, also comply with the backstop standards contained within the Cap-and-Trade Regulation.
- This standard includes a specific requirement that owners and operators of all affected EGUs, in addition to the general program requirements, surrender one CPP allowance for each ton of greenhouse gas emissions from affected EGUs.

The state measure in the Plan is the remainder of the Cap-and-Trade Regulation, as it applies to all other sources regulated by the state regulation, including other EGUs not covered by the CPP, as well as it applies non-CPP related requirements to EGUs. MRR is not being identified as a state emissions control measure, because it is not a control requirement, but its requirements also bind all entities participating in the Cap-and-Trade Regulation, and are incorporated into the relevant CPP portion of the Regulation. Relevant MRR provisions used for CPP compliance at affected EGUs will therefore also be federally enforceable.

The many complementary measures that help support compliance with the Cap-and-Trade Regulation, such as California’s Renewable Portfolio Standard and energy efficiency codes, play an important role in this system, but are not themselves identified as either emission standards or state measures. This is because the Cap-and-Trade Regulation accounts for their effects, and so is sufficient as the emission standard and state measure for the purposes of formal CPP compliance.

The regulations that enact these emissions standards and state measures are described in Table 7 below:

**Table 7 – Components of the Proposed Plan**

<b>Proposed or Final Regulation</b>	<b>Summary</b>	<b>Status</b>
Proposed 17 CCR § 95160	Defines source category of affected EGUs for reporting	Proposed state reporting requirement for Proposed Plan
Proposed 17 CCR § 95161	Adopts relevant CPP definitions for reporting	Proposed state reporting requirement for Proposed

		Plan
Proposed 17 CCR § 95162	Monitoring and recordkeeping requirements for affected EGUs	Proposed state reporting requirement for Proposed Plan
Proposed 17 CCR § 95163	Emissions and data reporting requirements for affected EGUs	Proposed state reporting requirement for Proposed Plan
Proposed and Final 17 CCR § 95859 and Appendix D	Establishes mass-based emission standards within the Cap-and-Trade Regulation and backstop emission standards for affected EGUs, provides interim and final targets, and requires compliance with relevant MRR provisions	Proposed emission standards and federally enforceable reporting requirements
17 CCR §§ 95800-96022 (excluding § 95859 and Appendix D)	State-level Cap-and-Trade Regulations, including definitions of compliance periods.	State measure

The full text of all of these regulations and proposed regulations is included in Appendix D.

## **5. Demonstration that the Proposed Plan Will Meet All CPP Targets**

### **5.1 Introduction**

The Proposed Plan will comply with the CPP CO<sub>2</sub>e emission goals established for California, as this required demonstration shows. (See 40 C.F.R. § 67.5745). This chapter, and its associated appendices, provide the emissions demonstration, unit-by-unit information, and CO<sub>2</sub> performance projections, required by 40 C.F.R. §§ 60.5745(a)(6), (a)(6)(iii), and (a)(6)(iv), and related requirements.

State plans for mass based goals must show that the state’s CPP program will be designed such that compliance by affected electric generating units (units) would achieve the CPP goal for each compliance period and interim step. This Chapter presents the detailed quantitative projections of energy and CO<sub>2</sub>e emissions from the affected units under the proposed “state measures” design and under a range of potential economic, demographic, and resource scenarios. This same quantitative analysis is used as the basis of an assessment of future planning reserve margins for the scenarios.

U.S. EPA requires that state plans include a description of the measures states will rely on to achieve the applicable CO<sub>2</sub>e emission goals and the associated laws, regulations or programs to implement them. State plans must also include information on the anticipated future operation of affected units, including projected characteristics of generators such as annual generation, CO<sub>2</sub>e emissions, fuel use, fuel price, fuel carbon content, heat rates, capacity and capacity factors among other things. In addition, state plans must include projected electricity demand (energy and peak) at the state and regional level, including the source and basis for estimates, as well as any underlying assumptions such as economic and population growth, or other factors driving demand. The analysis presented in this Chapter was developed by an Interagency Team composed of the staff from the California Energy Commission (Energy Commission), the California Public Utilities Commission (CPUC) and the California Air Resources Board (ARB). The analyses were performed and documented by Energy Commission staff.

Section 5.1 describes the tools, methods and models used in the quantitative assessment of future electricity generation and CO<sub>2</sub>e emissions. Section 5.2 presents the results and findings for a Reference Case and Stress Case scenario developed to assess the resiliency of the future generation system and levels of CO<sub>2</sub>e emissions under both expected and unusual system conditions. Detailed descriptions of the underlying modeling assumptions are included in Appendix E.

The overall conclusions of this section are that the Cap-and-Trade Regulation, which incorporates the effects of and is supported by many complementary energy sector policies, supports compliance with the CPP. Indeed, even under the conservative scenario modeled as the base case (under which California does not further tighten its climate and energy laws and policies), compliance is amply achieved. An even more conservative stress case, which is designed to strain the system and emphasize conditions under which emissions from existing EGUs might increase also achieves compliance. In reality, California's policy structure is likely to be substantially *more* stringently focused on reducing GHG emissions than either of the modeled scenarios, meaning that compliance with the CPP is assured, plausibly at emission levels well below those described in the modeled results.

## 5.2 Analytical Methods & Tools

The modeling described in this demonstration is based upon multiple stakeholder-driven planning and research processes conducted by expert agencies throughout California. This section describes those processes and the PLEXOS production cost model, a widely used model that the CEC has licensed, used to develop the modeling demonstration discussed below.



### 5.2.1 California Electricity Planning Processes

Much of the modeling below is based upon demand forecasts and electricity system projections developed through existing state-level stakeholder processes. They are described below.

California has three primary forums for electricity system planning involving its three energy agencies: the Energy Commission, the CPUC and the California Independent System Operator (California ISO). The three agencies coordinate their planning processes closely to ensure consistency in the data, assumptions and scenarios that serve as the basis for decisions about the need for generation resources and transmission infrastructure in the state.

Every two years Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the Energy Commission to prepare a biennial Integrated Energy Policy Report (IEPR) that assesses major energy trends and issues facing the state's electricity and other energy sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (Public Resources Code § 25301[a]). The Energy Commission prepares these assessments and associated policy recommendations every two years, with updates in alternate years.

Preparation of the IEPR involves close collaboration with federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues. As part of the IEPR the Energy Commission adopts the California Energy Demand (CED), which forecasts electricity demand over a 10 year timeframe. The most recent demand forecast, the CED 2015 Revised is used by both the CPUC and California ISO in their respective planning processes.<sup>23</sup>

The CPUC's Long-Term Procurement Proceeding (LTPP) process, established in 2002 by AB 57 (Public Utilities Code § 454.5), is intended to ensure safe, reliable, and cost-effective electricity supply for California's investor owned utilities (IOU) by analyzing the need for capacity resources on a 10-year planning horizon. To capture the geographic and operational complexity of the California grid, the LTPP evaluates need for three categories of capacity: system-wide (or generic), local (for transmission-constrained areas), and flexible (resources that can ramp up or down quickly). The assumptions used in this evaluation are developed in conjunction with the Energy Commission (which provides the demand forecast) and the California Independent System Operator (which uses the same assumptions for transmission planning). If capacity needs are found, the LTPP process can authorize IOUs to procure long-term contracts. The LTPP is closely and formally linked with the energy agencies' processes. The LTPP uses the demand forecasts developed by the CEC and the LTPP generates resource scenarios used in the ISO's Transmission Planning Process.

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<sup>23</sup> *California Energy Demand 2016-2026*, Revised Electricity Forecast, California Energy Commission, Publication Number: CEC-200-2016-001-V1.

The California ISO Transmission Planning Process (TPP) is conducted on an annual basis to establish a formal roadmap for the infrastructure requirements of the California ISO's balancing authority. The TPP provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to successfully meet California's policy goals, in addition to examining conventional grid reliability requirements and projects that can bring economic benefits to consumers. This plan is updated annually, and is prepared in the larger context of supporting important energy and environmental policies while maintaining reliability through a resilient electric system. The California ISO establishes guidelines and standards in addition to those established by North American Electricity Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) to ensure the secure and reliable operation of the California ISO controlled grid. The TPP uses the demand forecast developed by the CEC in the IEPR and resource assumptions and scenarios developed in the CPUC's LTTP as a basis for determining the transmission and other infrastructure necessary to ensure grid reliability.

Insights and products from these processes have informed the demand forecast, supply and demand assumptions, scenarios, and modeling approach used in this Proposed Plan. The IEPR process, in particular, including its demand forecast, was used as the basis for the modeling used in this Proposed Plan. A full description of the construction of the demand forecast is provided in Appendix E.

### 5.2.2 Modeling the Electricity System

With the information from the IEPR process in place, the next step was to model the behavior of the affected EGUs for CPP compliance. The Energy Commission staff uses the PLEXOS Integrated Energy Model, which is a production cost optimization model used by many entities in the electricity sector, to model resources in the Western Electricity Coordinating Council.<sup>24 25</sup> Using user-defined grid-wide electricity demand as a model input, PLEXOS determines the array of potential generating units capable of meeting the demand given the various constraints on power generation units, transmission capacity limitations, and the need to maintain grid reliability. PLEXOS and other production-cost models use heat rates, fuel costs and variable operating costs for each available unit to optimize generation output based on the lowest possible cost to meet all constraints. The dataset used to develop these compliance plans models the entire Western Electricity Coordinating Council (WECC) grid.

As PLEXOS inputs, users define electric generator constraints, peak and total energy demand, transmission costs and limitations, fossil fuel costs, and the composition of the generation fleet including preferred resources. PLEXOS develops a least-cost dispatch of available resources accounting for the defined constraints and the need to maintain

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<sup>24</sup> Platform owned by Energy Exemplar Ltd. <http://energyexemplar.com/software/plexos-desktop-edition/>

<sup>25</sup> The WECC Region extends from Canada to Mexico and includes Canadian provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western United States.

grid reliability. Generator dispatch costs are calculated using defined heat rate curves and fuel costs, regulatory costs including GHG emissions, as well as other variable operating costs. Power transmission costs are calculated using defined wheeling rates and regulatory adders for fossil-fuel generation.

The Energy Commission staff develops a data set that characterizes the grid for the entire Western Electric Coordinating Council (WECC) Region in which the California system operates. The list of generating units used by the model consists of units identified by California Energy Commission (CEC) staff, along with WECC's Transmission Expansion Planning Policy Committee (TEPPC), as capable of selling power to the WECC grid.<sup>26</sup>

In the 2015 IEPR, the Energy Commission staff continued to use the PLEXOS model to estimate natural gas demand in the power generation sector for the WECC. In this platform, staff developed a WECC-wide production simulation model dataset covering the years 2015-2026 for the three IEPR common cases. California's electricity supply and demand assumptions reflect current policy and mandates. For the rest of the WECC, staff begins with the TEPPC 2024 common case and the most current year (2013) of historical supply and demand data to develop the 2015 – 2026 details missing from the single year TEPPC common case.

The PLEXOS simulation dataset developed to provide fuel demand for natural gas generation for 2015 – 2026 uses two major sets of assumptions, California-specific and those for the rest of the WECC. Each set has a set of electricity load forecasts and supply portfolios. From the fuel demand for natural gas staff is then able to calculate CO<sub>2</sub>e emissions associated with the electricity system.<sup>27</sup>

### *Self-Generation and Combined Heat and Power*

In developing heat rate curves and corresponding capacity curves used by PLEXOS, Energy Commission staff exclude self-generation and combined heat and power useful thermal output (UTO) that do not deliver power to the grid. Since this on-site generation is not captured in PLEXOS, the fuel use and UTO for self-generation and combined heat and power are calculated exogenous from the model. The Energy Commission staff de-rates the nameplate capacity of these units based on the historic operating data to account for the percentage of the total capacity available for delivery to the grid. To determine the amount of fuel use to exclude to account for the UTO portion of a combined heat and power generation unit, the Energy Commission assumes either a 40% or 60% reduction from the unit's full load heat rate depending on the unit parameters and historic operations data. The de-rated nameplate capacity and heat rates are then used to populate the generating unit information in the model. As a

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<sup>26</sup> The TEPPC, a committee set up by WECC, oversees and maintains public databases for transmission planning, coordinates the planning process, conducts transmission studies and prepares Western Interconnection-wide transmission plans.

<sup>27</sup> Future details from simulation models on a plant by plant basis are not accurate forecasts, but the results for the aggregate for similar types of plants are robust.

result, only the portions of nameplate capacity and heat rates dedicated to grid power generation are included in the model output.

The Energy Commission staff typically excludes on-site generation in running the model since it is most concerned with balancing grid demand and supply and, as a result, the exclusion of on-site self-generation and UTO by PLEXOS makes sense. However, the CPP requires the inclusion of on-site self-generation and UTO when determining covered units and compliance with the CPP emission targets. The on-site generation not characterized in a production cost model is handled through post processing of historic generation from the Energy Commission's Quarterly Fuels and Energy Report (QFER) database. The 2014 QFER data for on-site use of generation is used to determine the generation associated with on-site self-use.

The same U.S.EPA fuel-specific emission factor from PLEXOS is applied to this on-site portion to estimate the associated emissions. It is assumed that on-site generation remains constant unless the plant is retired from 2020 to 2031.<sup>28</sup> The UTO amount and associated emissions come from the latest available Energy Information Administration (EIA) dataset, 2014 is the year used for this estimate. Similar to on-site generation, they are assumed to remain constant, unless the unit is retires, over the 2020-2031 timeframe. These two post processing additions to the PLEXOS outputs complete the modeling domain for this analysis.

#### *Method for Post Processing Emission Results*

As prescribed by U.S.EPA, the mass based emission target (US EPA mass target) was recalculated based on the final list of "affected units," holding all other values constant.<sup>29</sup> To determine whether the CO<sub>2</sub>e emissions for the two scenarios developed by staff were in compliance with the U.S. EPA mass target, Energy Commission staff calculated the annual mass CO<sub>2</sub>e emission (in short tons) associated with the modeling results.

Two scenarios (described below) were constructed using assumptions from the IEPR and LTPP to project future resource development and retirements.<sup>30</sup> The PLEXOS simulations provide estimates of annual generation and fuel use based on heat rate curves for each unit in the WECC through 2026. Staff then culled out all affected units into a spreadsheet to convert the plant's forecasted fuel use into short tons of CO<sub>2</sub>e using US EPA's emission factors (lb/MMBtu) by fuel type.<sup>31</sup> These generation and fuel use projections coupled with the EPA specific emission factors by fuel type are the basis for emissions projections through 2026 for all CPP affected units. For 2027-2031

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<sup>28</sup> If a unit reaches 40 years old and lacks a power purchase agreement, the entire unit is assumed to be retired in its 40th year of operation.

<sup>29</sup> Energy Commission staff used the ARB's most current list of "included" and "excluded" units in determining California's rate and mass based emissions. An included unit refers to those generators that are subject to the CPP, also referred to as affected units.

<sup>30</sup> These scenarios and the underlying assumptions are described in Sections 3, 4 and 5.

<sup>31</sup> The estimated natural gas consumed (in Btu) for electric generation is multiplied by the US EPA's natural gas CO<sub>2</sub>e rate of 117.1 lb. CO<sub>2</sub>e/MMBTU, while forecasted coal consumed in California is multiplied by 205.3 lb. CO<sub>2</sub>e/MMBTU.

staff extrapolated PLEXOS 2026 results annually based on the average annual growth rate of the total affected units generation between 2025 and 2026. To calculate the annual unit specific generation for 2027-2031 the ratio of each unit's contribution to the total 2026 affected generation was assumed to persist in each extrapolated year. The 2027-2031 fuel use by unit was calculated based on their 2026 implied annual heat rate and extrapolated generation.

### 5.3 Case Construction and Results for Reference Case and Stress Case Scenarios

As part of their CPP Plan, the EPA requires states to demonstrate that the affected units will meet the EPA CO<sub>2</sub>e emissions target for the interim period, each interim step, and the final period. To demonstrate that the CO<sub>2</sub>e emissions that can be expected from California's affected units comply with the targets set under the CPP, the Energy Commission staff developed two scenarios. The first is a Reference Case based on the Energy Commission's IEPR Mid Demand Case that projects the generation and fuel use by affected units based on current state and federal policies and mandates.<sup>32</sup> The second is a Stress Case that uses the High Demand Case, but includes the same assumptions regarding current policies and mandates. However, the Stress Case is characterized by conditions where natural gas generators would be more heavily relied on than in the Reference Case. A detailed description of the assumptions and values informing the IEPR cases is included in Appendix E.

The demand side assumptions from the Mid and High Demand Cases are derived from the Energy Commission's most recent demand forecast. This includes assumptions such as the impacts of energy efficiency, distributed generation, electric vehicles and other factors affecting demand. The detailed supply side assumptions used in the modeling for items such as renewable resources, power plant retirements and additions, hydro availability, imported power, CO<sub>2</sub>e and fuel prices are presented in Appendix E. Imported power for both the reference and stress case includes California's ownership shares of resource located out of state.

Additionally PLEXOS allows economic imports up to the WECC transmission path rating limits. California's ownership shares of CO<sub>2</sub>e emitting resources are assigned the same CO<sub>2</sub>e price adder as CO<sub>2</sub>e emitting resources in California, plus a transmission charge. California's ownership shares of non-CO<sub>2</sub>e emitting resources are assigned only the transmission rate. Any additional economic imports (unspecified power) to California are assigned a proxy CO<sub>2</sub>e cost as well as a transmission charge. As discussed above, the generation and fuel use results are then post-processed to determine the mass CO<sub>2</sub>e emissions associated with the Reference Case scenario.

To further demonstrate compliance with mass targets throughout the forecast period, the Energy Commission staff constructed a Stress Case in which there would be a very

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<sup>32</sup> California Energy Commission, *California Energy Demand 2016 – 2026, Revised Electricity Forecast (2015 CED Revised)*, January, 2016, CEC-200-2016-001-V-1. The demand forecast includes three cases: high demand, mid demand and low demand.

high natural gas burn by affected units driving high levels of CO<sub>2</sub>e emissions. To construct this case, the Energy Commission used the following major assumptions:

- **Low Hydro Power:** California hydro generation is restricted, while all other WECC hydro generation is assumed to remain at average levels throughout the forecast period. Low hydro power production forces more reliance on in-state power generation from natural gas fired units, many of which are subject to Rule 111(d). These plants must operate much more than otherwise expected in order to meet the energy demand.
- **High Demand Case:** economic, demographic, low prices and other conditions that lead to high electricity demand growth through the forecast period. To meet this higher demand, California would have to rely on a greater amount of generation from affected units.
- **CO<sub>2</sub>e Price Projections:** The low CO<sub>2</sub> price projections from the high demand case were replaced with the mid CO<sub>2</sub> price projections from the mid demand case for California CO<sub>2</sub> emitting resources. For non-California CO<sub>2</sub> emitting resources the low CO<sub>2</sub> price projections were added to reflect a WECC wide CO<sub>2</sub> pricing assumption.
- **Diablo Canyon Out:** The current operating licenses for Diablo Canyon expire in 2024-2025 and it is assumed that relicensing of the units does not occur. Retiring these zero CO<sub>2</sub>e emitting units would, in this scenario, cause affected units to operate more to make up for the lost generation.<sup>33</sup>

For the Reference Case, the CO<sub>2</sub>e price projections from the mid demand case are also used for California CO<sub>2</sub>e emitting resources. For CO<sub>2</sub>e emitting resources located outside of California the CO<sub>2</sub>e price projections from the low demand case were used.. As with the reference case, the stress case simulation results were used to estimate generation, fuel use and CO<sub>2</sub>e emissions associated with the affected units.

The CO<sub>2</sub>e price projections used for the modeling are as follows:

**Table 8: CO<sub>2</sub>e Price Projections  
(nominal dollars per metric ton)**

Year	California	Rest of WECC
2020	27.15	18.10
2021	29.22	19.48
2022	31.45	20.97

<sup>33</sup> Shortly before the release of this Proposed Plan, Pacific Gas & Electric announced a proposed settlement to retire Diablo Canyon and replace it with zero-emitting resources. If this settlement is approved, and is effective, it would further underline the likelihood of California emissions falling well below CPP target levels.

2023	33.86	22.57
2024	36.46	24.31
2025	39.26	26.18
2026	42.30	28.20
2027	45.59	30.39
2028	49.15	32.77
2029	53.01	35.34
2030	57.19	38.13

Source: California Energy Commission, Supply Analysis Office

It is important to emphasize that these results are very conservative, for several reasons. First, the modeling for this analysis did not simulate the effects of a recently enacted statute, SB 350 (Statutes of 2015, De Leon), which further intensified California’s electricity sector decarbonization efforts. A full description of SB 350 can be found in Appendix F. In brief, the statute expanded renewable procurement requirements for California utilities to 50% or more, embedded greenhouse gas emissions reduction in a new integrated resource planning process for most utilities, and set targets for greatly increased energy efficiency.

Second, nor did the modeling account explicitly for more stringent economy-wide carbon targets or their incorporation into the Cap-and-Trade Regulation. As discussed above, ARB is proposing significant amendments to that Regulation that would put covered entities in the Program on a trajectory towards steep emissions reductions in 2030 and 2050, as well as expanding the program to include Ontario’s program.

In both cases, these effects are expected to be significant, but were unnecessary to model for this demonstration, because they can only result in further reductions from California’s affected EGU emissions which (as the results below show) fall well below CPP targets even under status quo and stress conditions. Moreover, because the precise policies to be employed to implement SB 350, and the precise terms of the final Cap-and-Trade Regulation are being developed in parallel with this proposed Plan, and so cannot be precisely modeled at this time. However, it is clear that none of these pending changes could increase California affected EGU emissions. To the contrary, they will put increased pressure on those units to reduce their emissions, likely even further below CPP targets. As these new policies are implemented, California’s emissions from affected EGUs are likely to fall even further.

### 5.3.1 Energy & Emissions Results

Table 9 and Table 10 provide mass based results for the Reference and Stress Cases compared to the U.S. EPA targets for California’s affected units. The 2014 data reflect actual reported values while 2020-2026 values are derived from the PLEXOS simulations for each case. As described in an earlier section, the 2027-2031 values are extrapolated using the average annual growth rate from 2025-2026. Under both the Reference and Stress Case, California is projected to be below the U.S. EPA target in

all years. By 2031, California emissions are below the U.S. EPA target by 34 % under Reference Case conditions and 5 % under the Stress Case. Note that “targets” displayed are annual values, intended to illustrate compliance with the CPP glidepath, rather than the binding legal multi-year targets set for each interim step. They sum to the required CPP values for the interim and final periods. Please note that values here, unlike in the formal target table, are displayed in short tons, as opposed to metric tons.

**Table 9: Summary of CO<sub>2</sub>e Emissions Estimates for the Mid-Case**

Year	California Emissions Estimates (Thousand Short Tons)	US EPA CPP Glidepath Emissions (Thousand Short Tons)
2014	45.4	
2022	37	55.1
2023	35.7	54.5
2024	34.4	53.9
2025	35.2	53.3
2026	34.9	52.7
2027	34.5	52.1
2028	34.2	51.5
2029	33.9	50.9
2030	33.6	50.3
2031	33.3	50.3

Source: California Energy Commission, Supply Analysis Office

**Table 10: Summary of CO<sub>2</sub>e Emissions Estimates for the Stress Case**

Year	California Emissions Estimates (Thousand Short Tons)	U.S.EPA CPP Glidepath Emissions (Thousand Short Tons)
2014	45.4	
2022	45.7	55.1



2023	44.2	54.5
2024	43.4	53.9
2025	48.4	53.3
2026	48.4	52.7
2027	48.4	52.1
2028	48.3	51.5
2029	48.3	50.9
2030	48.3	50.3
2031	48.2	50.3

Source: California Energy Commission, Supply Analysis Office

Appendix E presents an overview of major assumptions on both the supply and demand side that underlie this analysis. In addition, unit specific results and characteristics are presented as indicated below. However, the following caveat is important to understand when reviewing plant specific results. Simulation tools, such as the PLEXOS software, are useful tools for estimating the dispatch of the power system given a number of simplifying assumptions to approximate how the electricity system might function under given conditions. However, the actual unit-level dispatch of the future electricity market depends on unknowable market factors. Rather than being selected by their relative costs when compared with other available power plants, the market functions to select which power plants to dispatch based on the bids of the different participating generators.

The results from the model simulations indicate what plants, from a group of available power plants, could be dispatched under the assumed conditions, not the actual plant or unit level commitments. As a result, while unit specific results are presented in the Appendices, they should not be considered accurate forecasts of which plants would actually be called on in the electricity market in future years. They are merely approximations of how units might be operated.

Energy Commission staff closely reviewed plant by plant simulations results and found them to be robust for groups of plants, as a whole, given the assumptions. As previously stated, future details from simulation models on a plant by plant basis should not be considered as precise forecasts, however the aggregate for similar types of plants is robust.

In addition to the statewide results presented above, more detailed results and assumptions required by U.S. EPA in the CPP can be found as follows:<sup>34</sup>

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<sup>34</sup> Fed. Reg. 64945

- A detailed description of the construction of all relevant IEPR cases is provided in Appendix E.
- Detailed annual energy and emissions results for Reference Case and Stress Case are shown in Appendix E1.
- Summary of unit operating characteristics including: annual generation, CO<sub>2</sub>e emissions, fuel use, heat rates, capacity and capacity factors for both cases are shown in Appendices E2a and E2b.<sup>35</sup>
- As part of the simulation modeling fuel prices for individual units are not applicable, however several aggregate prices used in the simulation modeling are presented as follows:
  - CO<sub>2</sub>e prices are shown in Table 8 of this document and in Table 12 of Appendix E
  - Natural gas burner tip prices are shown in Appendix E3.
  - Coal prices are shown in Appendix E4.
  - Wholesale electricity prices in Appendix E5.
- Statewide peak and energy demand forecast scenarios, including justification and documentation of underlying assumptions are presented in Appendix E including:
  - Annual economic and demographic trends,
  - Personal income,
  - Employment,
  - Households,
  - Manufacturing output,
  - Electricity rates,
  - Energy efficiency,
  - Electric vehicles and other transportation electrification,
  - Demand response, and
  - Climate change impacts.
- Assumptions regarding California and WECC-wide supply, along with WECC-wide demand, are presented in Appendix E, including:
  - Demand for other states in the WECC
  - Power plant retirements and additions,
  - Hydroelectric availability, and
  - Renewable resources and profiles.

### 5.3.2 Interstate Effects and Affected and Non-Affected Source Leakage Analysis

As part of the modeling assumptions for this analysis, Energy Commission staff included a WECC-wide CO<sub>2</sub>e cost adder for fossil-fuel generation as well as a CO<sub>2</sub>e price for imported power into California. Below is a summary of the approach used to

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<sup>35</sup> Individual unit fixed and variable O&M costs are not applicable.

assign prices in the model, and the results of analyses of potential interstate effects associated with the model's projections, as well as an analysis demonstrating that emissions leakage to new EGUs in California is not projected to occur as a result of CPP compliance (see 40 C.F.R. § 60.5790(a)(5)).<sup>36</sup> It is important to emphasize that the CPP explicitly requires consideration only of potential in-state linkage between new and existing EGUs; staff have included the interstate consideration for completeness and to assure that this Proposed Plan satisfactorily reduces emissions.

### *Interstate Effects*

To model how the system might perform under the CPP, Energy Commission staff assumed that other WECC states would begin pricing CO<sub>2</sub>e emissions in some way. To capture this assumption, staff assigned an emissions price for fossil-based CO<sub>2</sub>e emissions from out-of-state resources. Staff assumed the CO<sub>2</sub>e price for other WECC states would be well below the estimated CO<sub>2</sub>e prices in California. Table 8 summarizes the annual prices used for both California and the rest of the WECC. It is important to emphasize that these scenarios are illustrative modeling results – not compliance strategies, or requirements. They simply illustrate that the CPP, in and of itself, will not lead to leakage in emissions from California to other states. These results illustrate potential results of the federal policy choices made in the CPP, as reflected in potential state compliance plans, rather than any new state policy decision.

Out-of-state generation imported into California would also be subject to California's Cap and Trade program, as they are now, which places a cap on the carbon intensity on power purchases made by California utilities. Imports into California were assumed to incur an additional cost, referred to as a hurdle rate, based on the quantity of power delivered to California and the generation type. Using the assumed emissions rates shown in Table 11, Energy Commission staff developed a hurdle rate based on the CO<sub>2</sub>e price projections. These hurdle rates were added to the existing wheeling charges for electricity delivered into California.

The amount of imported generation from utility ownership agreements and publicly available contractual agreements was assumed to be delivered to California proportional to generator output. Within the production cost model, additional electricity purchases are treated as unspecified purchases and are assumed to be natural gas. It was assumed that imports would be able to meet the 1,100 lbs CO<sub>2</sub>e/MWh Emissions Performance Standard established by California to limit long-term investments in high-CO<sub>2</sub>e baseload generation by the California's utilities. Imports from the Pacific Northwest were assumed to be a mix of hydro and wind (about 80 percent) and natural gas (about 20 percent).

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<sup>36</sup> ARB staff take emission leakage very seriously. However, California program design appears to be accounting for this risk with regard to the CPP in California. Because a leakage risk does not appear to be present, ARB staff does not propose to include leakage measures specific to the CPP in this Proposed Plan. California's comprehensive Cap-and-Trade Regulation ensures that new and existing EGUs experience the same incentives, obviating leakage risk, as the demonstration shows.

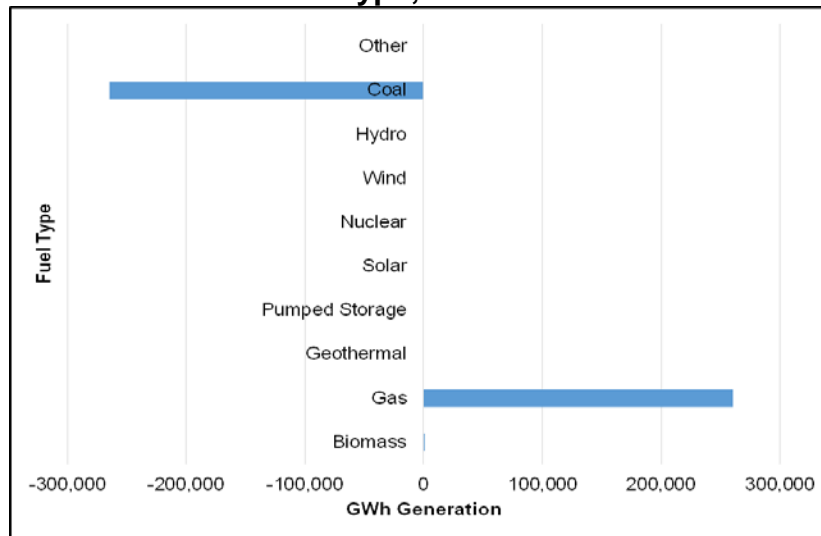
**Table 11: Hurdle Rate Assumptions**

Type	Tons CO <sub>2</sub> e/GWh
Coal	1,071
Renewables and Hydro	0
Existing Natural Gas	439
Nuclear	0
Unspecified	428
Unspecified - PNW	86

Energy Commission staff analyzed the effects of a WECC-wide CO<sub>2</sub>e cost adder and a hurdle rate on imports compared with a CA-only CO<sub>2</sub>e cost adder. The analysis compared the fuel consumption, or “burn” (in MMBtu) and electrical energy generation (in GWh) at both the WECC-wide and state-by-state levels in the years 2024 through 2026. Staff also examined impacts on transmission line flows into and out of California (imports/exports).

The total generation from all sources showed little change when a WECC-wide CO<sub>2</sub>e cost adder was used, as compared to a California-only CO<sub>2</sub>e cost adder. Figure 2 shows the difference in the total generation for the years 2024 through 2026, as illustrative, between the WECC CO<sub>2</sub>e cost adder /hurdle rate case and the California-only CO<sub>2</sub>e cost adder case.

**Figure 2: WECC Generation Changes Driven by Modeled CO<sub>2</sub>e Cost Adders by Fuel Type, 2024-2026**

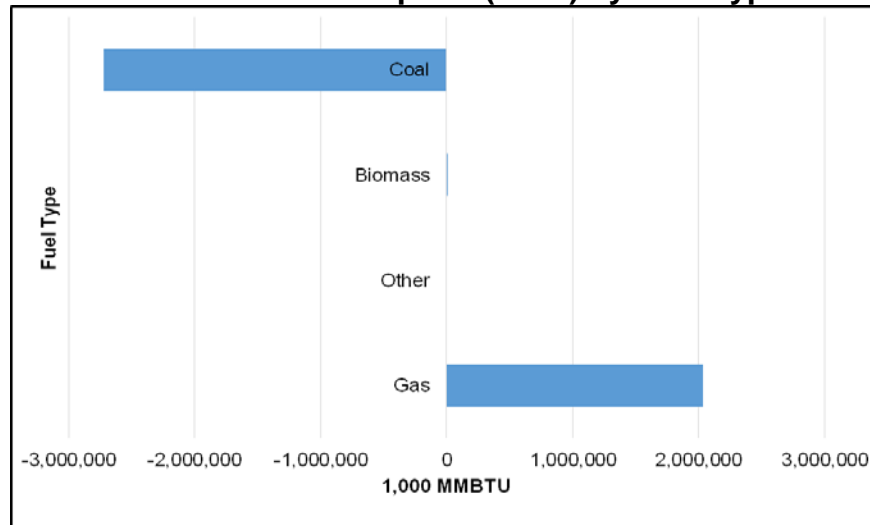


Source: California Energy Commission, Supply Analysis Office

In Figure 2, when a WECC-wide CO<sub>2</sub>e cost adder/hurdle rate was included, coal-fired generation decreased 35% while natural gas-fired generation increased by 27%. This is consistent with other modeling results done by U.S. EPA, which show a shift from coal to natural gas generation in the West that would be likely to occur under the CPP.

WECC-wide fuel use, for all fossil fuel resource types, decreased by 4.5% when a WECC-wide CO<sub>2</sub>e cost adder was assumed. With a WECC-wide CO<sub>2</sub>e cost adder coal fuel use decreased by 35% while natural gas fuel use increased by 29% as shown in Figure 3. The other fuel types remained roughly the same.

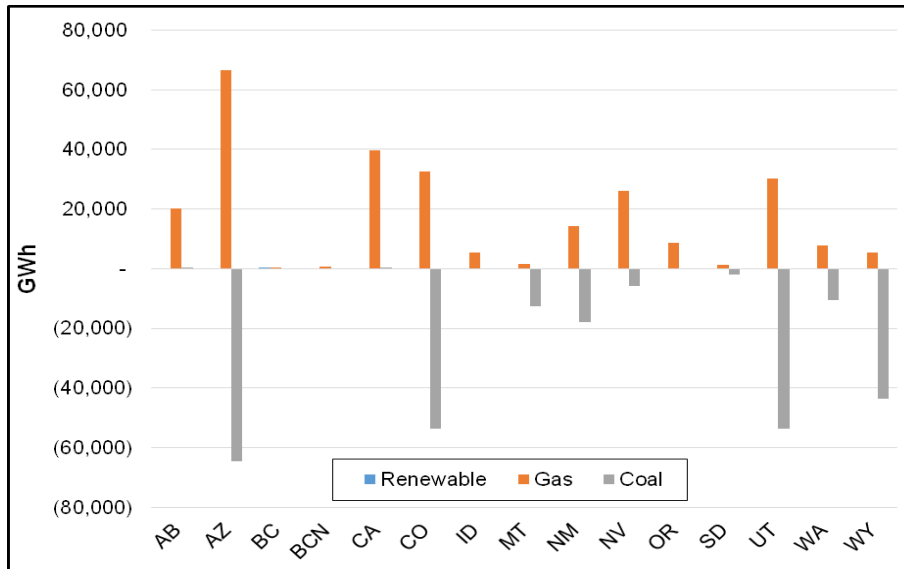
**Figure 3: WECC Fuel Consumption (Burn) by Fuel Type 2024-2026**



Source: California Energy Commission, Supply Analysis Office

Energy Commission staff examined generation state-by-state based on three resource categories: renewables, natural gas, and coal. Natural gas showed the largest increase while coal showed the biggest decrease when assuming a WECC-wide CO<sub>2</sub>e cost adder/hurdle Rate. Arizona, Colorado, and Utah showed the largest changes in natural gas and coal use. See Figure 4

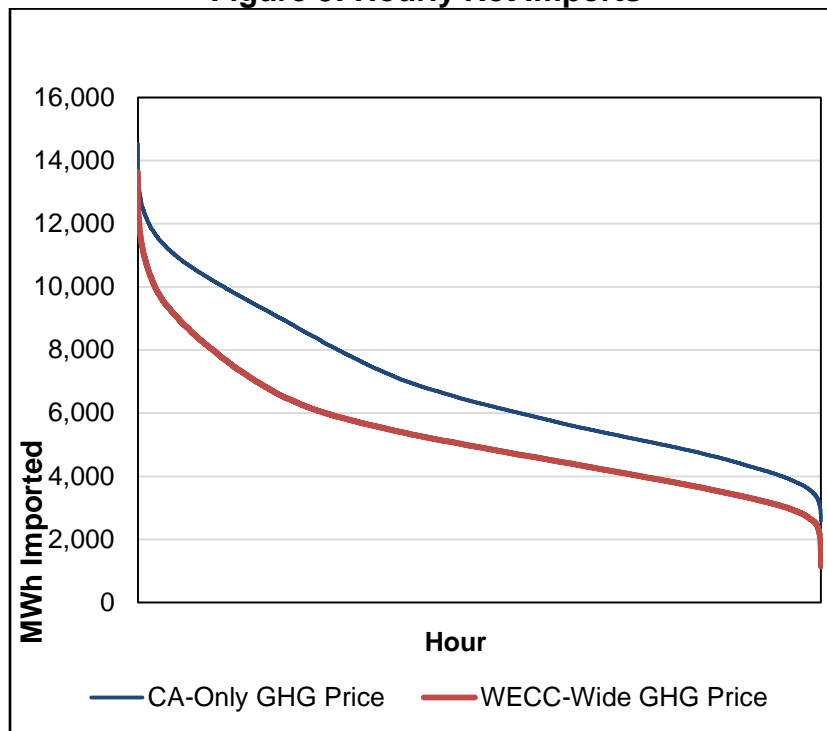
**Figure 4: Generation by Fuel Type and State 2024-2026**



Source: California Energy Commission, Supply Analysis Office

Energy Commission also examined any changes in electricity imports into California. With a WECC-wide CO<sub>2</sub>e cost adder/hurdle rate, hourly imports became more variable. Figure 5 shows hourly electricity imports ordered from highest to lowest (left to right). Overall, using a WECC-wide CO<sub>2</sub>e cost adder/hurdle rate decreased generation and fuel use from coal while increasing it for natural gas resources.

**Figure 5: Hourly Net Imports**



Source: California Energy Commission, Supply Analysis Office

Figures 4 and 5 show that a regional CO<sub>2</sub>e policy such as the CPP will change the operational characteristics of western power plants, but not result in leakage of emissions from California CPP affected units to the Western region as a whole. Particularly looking at California, we see that the economic dispatch of generators increases the operation of in-state natural gas units. This is also supported by the lower net imports into California shown in Figure 5. Overall, this would appear to indicate that leakage from California generation into other states is not a major concern. This result is also consistent with analysis done in support of the CPP showing less coal generation in the West, and reliance by California on its own natural gas fleet.

### *Leakage Analysis for New and Existing Units*

The CPP requires states to ensure that their plans address potential “leakage” – by which U.S. EPA means incentives to shift emissions to non-affected EGUs, reducing effective emission reductions -- between affected and non-affected EGUs within the state as a result of CPP implementation. (See 40 C.F.R. § 60.5790(b)(5)). Avoiding leakage is of critical importance<sup>37</sup> to ensuring the environmental integrity of CPP compliance plans.

California’s primary strategy for addressing leakage of this sort is based on its economy-wide Cap-and-Trade Regulation, which covers EGUs generally, both new and existing. Because the Cap-and-Trade Regulation imposes more rigorous requirements than the CPP, and imposes the essentially the same central set of carbon costs and compliance obligations on affected and non-affected EGUs, it acts as state measure (with regard to non-affected EGUs) and emission standard (with regard to affected EGUs) removing leakage incentives. For this reason, though ARB staff is not proposing a new set of formal leakage avoidance measures (such as adopting the optional “new source complement” into this proposed plan), staff believes measures now in force provide the functional equivalent.

To further determine if leakage may be an issue between existing affected generation, imports and new or non-affected generation in California, simulation generation results for the 2026 Stress and Reference Case were compared to 2014 actual data. Table 14 shows the percentages of generation in relation to the different categories. What this table shows is the normal trade-off between imports and in-state generation given the level of demand and differing supply portfolios, rather than any change in incentives or emissions between sources as a result of this Proposed Plan. Generation from new sources gradually increases over the modeled period, but appears to do so solely as a result of planned retirements and demand increases, rather than any shift in behavior related to the CPP. The increased reliance on imports in the Stress Case is caused by the assumed retirement of Diablo Canyon, lower than average hydro conditions and increased demand. However, these changes in projected imports even for the Stress Case are still below historic levels while affected generation is close to or above historic

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<sup>37</sup> ARB has also submitted comments to U.S. EPA urging that any federal model plan address this issue carefully and effectively.

levels. This supports the conclusion that these portfolios do not create leakage to non-affected California generation or imported power.

**Table 12: Comparison of Scenarios and 2014 Actual Percentage Generation by Category**

	2026 Stress Case	2026 Mid Case	2014 Actual
California CPP Portfolio Generation	37%	30%	33%
California Renewable Generation	22%	22%	15%
Non CPP California Generation	5%	10%	14%
New California Generation (Non CPP Portfolio)	5%	11%	0%
California Hydro Generation	7%	11%	6%
Imports to California (includes Renewables)	23%	16%	33%

Source: California Energy Commission, Supply Analysis Office

Based on these results, and California's comprehensive Cap-and-Trade Program, staff does not believe additional leakage prevention measures are necessary to include at this time. However, ARB staff will continue to monitor the issue, and expect – in particular – to closely evaluate leakage risk if any future regional CPP compliance strategies are proposed. It will be critical to ensure that the market program, including with any potential expansions, retains its environmental integrity. ARB staff anticipates working with U.S. EPA and any potential state partners to ensure that CPP compliance strategies address leakage properly.

#### 5.4 Summary of Demonstration

The analysis above demonstrates that affected EGUs in California will comply with federal CPP targets under a wide range of conservative scenarios, and that leakage will not occur as a result of the CPP. Because California's greenhouse gas reduction and energy policies will likely drive emissions reductions from the power sector even more quickly than in these conservative cases, compliance is likely to be achieved even more readily than these scenarios show. Indeed, these scenarios show that the CPP targets can be achieved even if California's emissions are maintained at or near 2020 levels.

The Cap-and-Trade Regulation integrates the effects of all these measures by setting an economy-wide emissions cap. Complementary measures in the energy sector help to support achievement of that cap, but the Cap-and-Trade Regulation ultimately guarantees the emissions reductions reflected by the declining cap is achieved across the capped sectors. The limited number of compliance instruments available, which must be used by all covered sectors, further limits the ability of the electricity sector to increase its share of total emissions, and is one of the major mechanisms that ultimately limits emissions from that sector, helping to support CPP compliance. Importantly, this



core dynamic – the limited availability of compliance instruments within the capped sectors – is independent of the price of compliance instruments.

The combined effects of California’s programs are projected to continue reducing greenhouse gas emissions from the sector, with Cap-and-Trade working to further support compliance. Of course, if compliance is nonetheless not achieved, the proposed backstop standards, described above, will restore the sector to compliance. U.S. EPA should have strong confidence that California will meet its CPP targets.

## **6. Demonstration that Identified State Measures Comply with CPP Requirements**

The CPP requires states to demonstrate that their state measures comply with certain fundamental requirements defined by U.S. EPA. (See 40 C.F.R. § 60.5745(a)(6)(iii). Specifically, U.S. EPA requires that state measures be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity. (40 C.F.R. § 60.5780(a)). The Cap-and-Trade Regulation is an emission standard with regard to affected EGUs, but is a state measure as it operates with regard to other covered entities. ARB staff therefore include this state measure demonstration as to each required characteristic.

### *Quantifiable*

A state measure is quantifiable if it can be reliably measured in a manner that can be replicated. (40 C.F.R. § 60.5780(a)(1)). As is described above, the Cap-and-Trade Regulation is supported by an extensive reporting framework, the MRR, which accounts for each ton of covered CO<sub>2</sub>e emitted from all covered sources. Mass emissions of greenhouse gases are then accounted for by compliance instrument surrender events, which are tracked by the Compliance Instrument Tracking System Service (CITSS), a management and tracking system for accounts and compliance instruments issued through the Cap-and-Trade Regulation and linked systems. CITSS is described in more detail later in this Proposed Plan and documentation for CITSS is included in Appendix G.<sup>38</sup> Because compliance with the Cap-and-Trade Regulation, like MRR, is measured through a comprehensive tracking system, as well through a comprehensive emissions reporting system, the measure is quantifiable.

### *Verifiable*

A state measure is verifiable if “adequate monitoring, recordkeeping, and reporting requirements are in place” to allow the state to “independently evaluate, measure, and verify compliance with the emissions standard.” (40 C.F.R. § 60.5780(a)(2)). Compliance with the Cap-and-Trade Regulation is tracked through the rigorous CITSS system, and emissions are tracked and recorded in the MRR’s own database, Cal e-

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<sup>38</sup> See also <https://www.wci-citss.org/>.

GGRT.<sup>39</sup> Public Cap-and-Trade compliance reports and emissions reports are posted on ARB's websites. Compliance with the state measure is therefore verifiable.

### *Non-Duplicative*

A state measure is non-duplicative if it is not "already incorporated as a State measure or emission standard in another State plan" unless it is part of a multi-state plan. (40 C.F.R. § 60.5780(a)(3)). The California Cap-and-Trade Regulation is not incorporated into any other State plan, and so is non-duplicative. The same is true of MRR.

### *Permanent*

A state measure is permanent if it must be "met for at least each compliance period" unless replaced by some other state measure or it is demonstrated to be unnecessary. (40 C.F.R. § 5780(a)(4)). The Cap-and-Trade Regulation requires compliance during each compliance period, and is permanently enforced until replaced. The underlying MRR is similarly permanently on the books. The proposed amendments to both regulations to support CPP compliance would be finalized before this Proposed Plan is submitted. The state measures are therefore permanent.

### *Enforceable*

A state measure is enforceable if it provides a technically accurate limitation or requirement, defines compliance requirements clearly, identifies entities responsible for compliance and liable for violations, is enforceable as a practical matter, and the state maintains the ability to enforce violations and secure appropriate corrective actions. (40 C.F.R. § 60.5780(a)(5)). The Cap-and-Trade Regulation, like the MRR, imposes clear emissions limitations and requirements on each affected entity, and clearly identifies those entities via its applicability sections. As a practical matter, these entities are responsible for their emissions and compliance, and may readily be enforced against. And as a legal matter, both the Cap-and-Trade Regulation and MRR clearly define violations (see, e.g., 17 CCR § 95107 (MRR enforcement) & 17 CCR §§ 96010-96014 (Cap-and-Trade enforcement)). ARB has extensive authority to take civil or criminal penalties and to seek injunctive relief for violations of these regulations. (See Cal. Health & Safety Code §§ 38580 (requiring and authorizing enforcement of AB 32 measures) & 42400-42410 (civil and criminal penalty provisions)). Indeed, ARB has already enforced both regulations extensively.<sup>40</sup> The Cap-and-Trade Regulation, like MRR, is therefore enforceable.

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<sup>39</sup> See also <http://www.arb.ca.gov/cc/reporting/ghg-rep/tool/ghg-tool.htm>

<sup>40</sup> Records of ARB enforcement settlements for all programs are maintained at <http://www.arb.ca.gov/enf/casesett/casesett.htm>.

## **7. Demonstration that Identified Emission Standards Comply with CPP Requirements (including with Mass-based Trading Requirements As Applicable)**

Emission standards in CPP compliance plans must meet requirements to be “quantifiable, permanent, verifiable, non-duplicative, permanent, and enforceable” with respect to each affected EGU. (40 C.F.R. § 60.5775). The emission standards in the Proposed Plan are those identified above within California’s Cap-and-Trade Regulation for affected EGUs, including the backstop emission standards, which operate within the Cap-and-Trade Regulation and would be implemented using the same systems (including for emission reporting and compliance instrument tracking) as are used for the Cap-and-Trade Regulation as a whole. These emissions standards meet U.S. EPA requirements for essentially the same reasons as the closely-related state measures components of the Cap-and-Trade Regulation do, as is discussed above. This section demonstrates compliance, and then goes on to demonstrate that an additional set of U.S. EPA requirements, for mass-based programs (see 40 C.F.R. §§ 60.5815-60.5825) are also satisfied.

### **Compliance with Core U.S. EPA Requirements**

#### *Quantifiable*

An emission standard is quantifiable if it can be reliably measured in a manner that can be replicated. (40 C.F.R. § 60.5775(b)). As is described above, the Cap-and-Trade Regulation is supported by an extensive reporting framework, the MRR, which accounts for each ton of covered CO<sub>2</sub>e emitted from all covered sources. Mass emissions of greenhouse gases are then accounted for by compliance instrument surrender events, which are tracked by the Compliance Instrument Tracking System Service (CITSS), a management and tracking system for accounts and compliance instruments issued through the Cap-and-Trade Regulation and linked systems. Because compliance with the Cap-and-Trade Regulation, like MRR, is measured through a comprehensive tracking system, as well through a comprehensive emissions reporting system, the emission standards are quantifiable.

#### *Verifiable*

An emission standard is verifiable if “adequate monitoring, recordkeeping, and reporting requirements are in place” to allow the state and U.S. EPA to “independently evaluate, measure, and verify compliance with the emissions standard.” (40 C.F.R. § 60.5775(c)). Again, because compliance with the Cap-and-Trade Regulation is tracked through comprehensive CITSS, and emissions are tracked and recorded in the MRR’s own database, Cal e-GGRT.<sup>41</sup> Public Cap-and-Trade compliance reports and emissions reports are posted on ARB’s websites. This information will also be shared with U.S. EPA through required state reports. Compliance with the emissions standards is therefore verifiable.

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<sup>41</sup> See also <http://www.arb.ca.gov/cc/reporting/ghg-rep/tool/ghg-tool.htm>

### *Non-Duplicative*

An emission standard is non-duplicative if it is not “already incorporated as an emission standard in another State plan” unless it is part of a multi-state plan. (40 C.F.R. § 60.5775(d)). The California Cap-and-Trade Regulation is not incorporated into any other State plan, and so is non-duplicative. The same is true of MRR.

### *Permanent*

An emission standard is permanent if it must be “met for at least each compliance period” unless replaced by some other emission standard or it is demonstrated to be unnecessary. (40 C.F.R. § 5775(e)). The Cap-and-Trade Regulation requires compliance during each compliance period, and is permanently enforced until replaced. The underlying MRR is similarly permanently on the books. The proposed amendments to the regulation to support CPP compliance would be finalized before this Proposed Plan is submitted. The emission standards are therefore permanent.

### *Enforceable*

An emission standard is enforceable if it provides a technically accurate limitation or requirement, defines compliance requirements clearly, identifies entities responsible for compliance and liable for violations, is enforceable as a practical matter, and the state, U.S. EPA, and third parties maintains the ability to enforce violations and secure appropriate corrective actions. (40 C.F.R. § 60.5775(f)). The Cap-and-Trade Regulation, like the MRR, imposes clear emissions limitations and requirements on each affected entity, and clearly identifies those entities via its applicability sections. As a practical matter, these entities are responsible for their emissions and compliance, and may readily be enforced against. And as a legal matter, both the Cap-and-Trade Regulation and MRR clearly define violations (*see, e.g.*, 17 CCR § 95107 (MRR enforcement) & 17 CCR §§ 96010-96014 (Cap-and-Trade enforcement)). ARB has extensive authority to take civil or criminal penalties and to seek injunctive relief for violations of these regulations. (See Cal. Health & Safety Code §§ 38580 (requiring and authorizing enforcement of AB 32 measures) & 42400-42410 (civil and criminal penalty provisions)). ARB regularly enforces its regulations, as a practical matter. Because the relevant requirements of the emission standards will be federally-enforceable upon U.S. EPA approval, and incorporated as appropriate into Title V permits issued to affected EGUs, they will also be enforceable by both U.S. EPA and third parties. The Cap-and-Trade Regulation, like MRR, is therefore enforceable.<sup>42</sup>

### *Compliance with U.S. EPA Requirements for Mass-Based Systems*

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<sup>42</sup> We note that ARB begins formal enforcement against entities that have untimely surrendered allowances only after an “untimely surrender” period during which compliance obligations are increased. Federal enforcement for failing to comply with applicable emission standards after initial deadlines have been missed might begin at an earlier time.

The CPP also contains several requirements for “mass-based trading program[s].” (40 C.F.R. §§ 60.5815-60.5825). ARB understands these requirements to apply only to emissions standards that use such programs (as opposed to state measures). It is not entirely clear whether these requirements apply to backstop emission standards for state measures plans, or whether they apply to all emission standards that may bear on affected EGUs if those standards involve mass-based trading programs. Without conceding that these requirements apply to the Cap-and-Trade Regulation as a whole, and out of an abundance of caution, and because the Cap-and-Trade Regulation and the proposed backstop standards, are part of a combined system, ARB staff address compliance as to the Regulation as it applies to affected EGUs, in addition to the backstop standards specifically. Three sets of requirements pertain.

### *Allocation Requirements*

The CPP provides that state plans must (1) include specifications for how allowances are to be allocated, along with provisions for adjusting allocations as needed, (2) provisions allowing for or restricting banking between compliance periods for affected EGUs, and (3) provisions not allowing any borrowing of allowances from future compliance periods by affected EGUs. (See 40 C.F.R. § 60.5815(b)-(f)). The Cap-and-Trade Regulation, including the backstop standards, complies with these requirements.

The Cap-and-Trade Regulation specifies how allowances are to be allocated as a general matter (though allocation is not available to affected EGUs (see 17 CCR §§95890-95895), which may acquire compliance instruments on the market or via auction. The backstop standards further specify how allocation is to be conducted in cases where those standards are triggered.

The Cap-and-Trade Regulation allows banking of allowances by registered entities. (17 CCR § 95922). Banking is not allowed between compliance periods for the backstop standards. These provisions satisfy U.S. EPA’s requirement that banking be addressed.

Finally, neither the Cap-and-Trade Regulation nor the backstop standards allow for borrowing from future compliance periods to support compliance. “Borrowing” is not a defined term in the CPP, but ARB staff understands that it refers to a practice by which compliance and emissions reductions may be deferred to future compliance periods. Borrowing of this sort does not occur in the California program. In three instances, vintage-less or future vintage allowances may be used in the program, but these uses are limited and do not implicate the substantive policy concerns which the anti-borrowing provision addresses.

First, vintage-less allowances may be released from an “Allowance Price Containment Reserve” (APCR) at reserve prices during designated reserve sales. (See 17 CCR § 95913). This price containment mechanism was populated by vintage-less allowances at the time the Cap-and-Trade Regulation began implementation in 2013 (See 17 CCR § 95870(a)), and contains millions of allowances. These allowances, as well as any additional allowances deposited into the reserve after 2020, are essentially banked

allowances – including millions of allowances banked in advance of the 2013-2020 period and removed from the compliance periods during that time-- and so do not implicate concerns of borrowing from compliance periods during the CPP.

Second, a very small number of EGUs which are operating as industrial cogeneration facilities may receive “true-up” allocations of future vintage allowances to mitigate leakage risk. This allocation does not affect the vast majority of CPP units, and is not designed to defer compliance to future periods. Instead, it is designed to ensure that covered units do not cease operations in California, displacing emissions. This is consistent with U.S. EPA’s policy intent to secure enforceable emissions reductions, and so does not implicate borrowing concerns associated with deferred compliance.

Finally, in the rare case that an entity does not comply with the timely surrender requirements of the Cap-and-Trade Regulation, it will be required to secure and surrender compliance instruments equal to four times its initial compliance obligation. (See 17 CCR § 95857). Three-quarters of these instruments will be restored to the auction. In these untimely surrender contexts, the larger compliance obligation may be made up via allowances issued in the next compliance period for the practical reason that the prior compliance period has already passed, with relevant allowances surrendered. Compliance is not deferred to the next compliance period; instead, the entity faces a larger compliance burden and must satisfy it within months of its initial failure to comply. This compliance incentive, too, does not implicate U.S. EPA’s concerns over deferred compliance.

#### *Allowance Tracking Requirements*

The CPP requires that mass-based trading systems operate using an U.S.EPA-approved allowance tracking system. CITSS provides all compliance instrument tracking needed by the California system, and can be used for both ordinary CPP compliance and in the event that a backstop event is triggered. (See 40 C.F.R. § 60.5820). Appendix G contains documentation and user guides explaining CITSS further. CITSS supports compliance with the CPP’s allowance tracking requirement. To wit, addressing each provision of that requirement:

*(a)(1) It electronically records the issuance of allowances, transfers of allowances among accounts, surrender of allowances by affected EGUs as part of a compliance demonstration, and retirement of allowances;*

All compliance instruments in CITSS are issued in CITSS. Each instrument is assigned a unique serial number when issued. Serialized instruments are not imported or exported from the system.

CITSS records the details of all instrument transfers among accounts. Records indicate the transferring and receiving accounts, number of instruments transferred, actions taken to complete the transfer, and the users taking the actions.

Every entity with a compliance obligation has a Compliance Account. Entities surrender instruments by transferring them to their Compliance Account. When an instrument is placed in a Compliance Account, that instrument cannot be removed from the Compliance Account by the entity. At each compliance deadline, CITSS calculates the compliance obligation and automatically retires the appropriate instruments from each Compliance Account. Retired instruments are transferred to a Jurisdiction Retirement Account established in CITSS.

*(a)(2) It documents and provides electronic, internet-based public access to all information that supports the eligibility of eligible resources and issuance of set aside allowances, if applicable, and functionality to generate reports based on such information, which must include, for each set aside allowance, an eligibility application, EM&V plan, M&V reports, and independent verifier verification reports.*

CITSS is available via a secure (https:) website. Access to CITSS is restricted to registered users. CITSS does not provide unregistered public access to the system or system reports, nor does ARB staff understand the CPP as requiring such access to confidential market data. CITSS does not contain nor publish information regarding the eligibility of EGUs to participate in the program. However, ARB maintains a clear record of all parties with Cap-and-Trade Program compliance obligations, and these parties are included in CITSS as they establish accounts. "Set-aside allowances" are not relevant or included in the Proposed Plan; in any event, applications, M&V reports, and independent verifier verification reports are maintained outside of the CITSS system.

It is important to emphasize that the public does have access to compliance reports generated with information from CITSS and other sources, and which are regularly posted on ARB's website. These reports provide compliance information by entity and can be used to identify non-compliant entities.

*(b) If approved in a State plan, an allowance tracking system may provide for transfers of allowances to or from another allowance tracking system approved in a State plan, or provide for transfers of allowances to or from an EPA-administered allowance tracking system used to administer a Federal plan.*

These requirements only apply if California's plan is linked to other state and federal CPP plans, which is not being proposed at this time. CITSS has the functionality to address such linkages if this becomes necessary in the future.

CITSS does not support the direct transfer of instruments between other tracking systems. All compliance instruments in CITSS are issued in CITSS. Each instrument is assigned a unique serial number when issued. Serialized instruments are not imported or exported from the system, and ARB does not expect to need to report serial numbers to U.S. EPA to demonstrate compliance.

An external process has been established to support use of instruments from other registries. When instruments (offsets) from another registry are to be issued in CITSS, the process is to ensure that the instruments are retired in the originating registry and once required documentation is provided that instruments have been retired, an equivalent number of instruments are issued in CITSS.

If needed in the future, a jurisdiction account could be created in CITSS to hold allowances for the purposes of the accounting for federal or state CPP compliance instruments. A process similar to that described above to import offset credits into CITSS could be established for allowances from another allowance tracking system approved in a state plan, or provide for transfers of allowances to or from an EPA-administered allowance tracking system used to administer a federal plan. (As noted elsewhere, separate state law requirements, in addition to these technical matters, would also need to be satisfied for market linkages).

### *Compliance Demonstrations*

The CPP requires that affected EGUs be able to demonstrate compliance by reconciling their emissions with the surrender requirements of the mass-based trading system. (See 40 C.F.R. § 60.5825). This is exactly what the Cap-and-Trade Regulation requires. (See, e.g., 17 CCR § 95856). ARB staff also note that surrender of allowances on a facility-wide basis for facilities made up of multiple affected EGUs is consistent with CPP compliance, which the Cap-and-Trade Regulations' facility-level design also supports. (See 40 C.F.R. § 60.5825(b)). The surrender requirements of the Regulation therefore meet all relevant U.S. EPA requirements.

## **8. Electrical Reliability Considerations**

EPA's final CPP requires that State Plan submissions include a demonstration that the state has considered reliability issues. (See 40 C.F.R. § 60.5745(a)(6)(A)). U.S. EPA does not make specific requirements for the form or content of the demonstration, but does write that "one particularly effective way" to make the demonstration is by documentation of an ISO/RTO/other planning authority "consultative process". The CPP preamble suggests that states should request a review of the plan by the planning authority at least once during the plan development stage and provide its assessment of any reliability implications.

The preamble calls for states to have a continuing dialogue with those entities during development of their final state plan, and document the consultation process, any response and recommendations from the planning authority, and the state's response to those recommendations. U.S. EPA stresses that the state is not obligated to follow the recommendations of the planning authority, and state plan submissions will not be substantively evaluated for reliability impacts. This documentation of a consultative process is the only demonstration explicitly described in the CPP. ARB and energy agency staff have followed such a process, working with energy agency staff and California Balancing Authority Areas.



To meet the requirements of the CPP for consideration of reliability implications of state plans, ARB, CPUC, and CEC staff have taken, and will continue to take, the following steps:

- The continuation of our ongoing, collaborative, multi-layered reliability planning currently undertaken to ensure reliability on long- and short-time scales.
- A prospective analysis of reserve margins achieved under various scenarios of Clean Power Plan compliance that will show adequate total resources to meet demand
- Consultation with balancing authorities in the state, including the California ISO.

California reliability planning authorities currently have multiple, layered processes in place to ensure reliability on both the short- and long-term basis. There are requirements to meet real-time operational reserves sufficient to correct for the single largest contingency and implement remedial action schemes to ensure short-term reliability. The state has one year-ahead resource adequacy requirements for its IOUs. In the long-term California conducts extensive resource planning to maintain adequate planning reserves.

This robust reliability framework has guided California planners, balancing authorities and load-serving entities through the substantial changes in the electricity system as large numbers of aging natural gas and nuclear power plants are retired and repowered and large amounts of intermittent renewables are added to the system. Because California expects to comply with the CPP through a continuation of these policies, California energy authorities will continue to primarily rely on these mechanisms to ensure reliability during the CPP implementation period.

California has further demonstrated its expectation of a reliable electricity system by assessing generation supply through the CPP compliance period. Energy Commission staff conducted a generation reserve margin analysis for the Reference and Stress Cases, described in an earlier section. This generation supply reserve assessment provides an additional broad measure of the reliability implications of California's CPP plan.

### 8.1 Existing Processes for Ensuring Reliability in California

California's set of operating and planning processes already provide, and are expected to continue to ensure reliability of the bulk power supply even as the state has implemented ambitious policies to modernize its natural gas fleet, retire aged fossil generation and bring online new low- or non-emitting resources. These processes are discussed below.

#### *Long-term Capacity and Transmission Planning*

The Energy Action Plan adopted by the CEC and CPUC following the energy crisis endorsed a planning reserve of 15-17 percent to guide procurement of resources,

including energy efficiency, renewables and clean fossil fuel power plants. Subsequently, the CPUC established reserve margins of 15-17 percent over peak demand as part of its long term planning and resource adequacy processes.<sup>43</sup>

Since 2003, the CPUC has engaged in a cyclical long-term procurement planning process in coordination with the CEC, California ISO, utilities and other stakeholders. The focus of these proceedings has been on ensuring reliability of the electric system while meeting the State's safety, environmental, and cost minimization goals. A ten year planning horizon is used when authorizing new resources, but reserve margins are also examined out 20 years. To capture the geographic and operational complexity of the California grid, the LTPP evaluates need for three categories of capacity: system-wide (or generic), local (for transmission-constrained areas), and flexible (resources that can ramp up or down quickly). Extensive modeling is conducted and subject to cross-examination within the proceeding. If the CPUC determines additional resources are appropriate, it may authorize utilities to procure the needed resources and share the cost with all benefiting customers. In authorizing new resources the CPUC takes into account the State's environmental goals and has authorized specific amounts of preferred resources (e.g. energy efficiency, wind, solar and/or storage resources) and generic resources. Annually, the CPUC issues a document detailing the assumptions and scenarios to be used in reliability planning. For example, the LTPP relies on demand forecasts developed by the CEC. An interagency group supports the demand forecast development. The California ISO's transmission plans and WECC common case also provide important study assumptions.

The planning process has been able to adjust to account for significant transformations in the California electric grid. For instance, since 2012, the Energy Commission, CPUC, and California ISO have successfully monitored and provided for reliable operation of the grid during the retirement or repowering of more than 10 GW of once-through-cooling power plants, the unexpected retirement of the 2 GW San Onofre Nuclear Generation Station, and the addition of more than 15 GW of variable renewable energy resources to the grid.

### *California Independent System Operator's Transmission Planning Process*

Similar to other independent system operators and regional transmission organizations operating in the United States, California Independent System Operator (California ISO) conducts an annual transmission planning process. California ISO's planning process takes a long-term (10 year) analytical approach to transmission planning pursuant to its tariff approved by the Federal Energy Regulatory Commission (FERC) and consistent with mandatory transmission planning reliability standards developed by the Electric Reliability Organization of North America (NERC) as well as California ISO's own planning standards. This process assesses and identifies reliability-driven, policy-driven, or economic-driven transmission system needs, ensures that California ISO meets all applicable reliability standards and planning standards, and also identifies efficient

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<sup>43</sup> For system reliability studies the CPUC uses a 1 in 2 weather year forecast as developed by the CEC in its biannual Integrated Energy Planning Report.

solutions to ensure continued compliance with those standards and reliable operation of the electric grid.

Since 2011, the California ISO's transmission planning process has identified transmission needs based on federal and state policies. This feature was reinforced by the final FERC rule known as Order 1000, which addressed regional transmission planning and cost allocation. This rule requires that transmission planning processes consider transmission needs driven by public policy requirements established by state or federal laws or regulations. A significant focus of the California ISO's policy-driven transmission planning has been to assess and identify transmission needs to achieve California's Renewables Portfolio Standard goal, among other goals.

California ISO's transmission planning relies on a consultative process. The California ISO, public utilities, state agencies and other stakeholders work closely together to assess how to meet environmental and reliability objectives. For example, California ISO and state agencies have worked to improve infrastructure planning coordination by developing unified assumptions for use within three core processes: (1) the CEC's long-term forecast of energy demand produced as part of its biennial Integrated Energy Policy Report; (2) the CPUC's LTPP proceeding, which authorizes new resource procurement; and (3) California ISO's annual transmission planning process. Each year California ISO consults with the state agencies and stakeholders to develop planning assumptions and scenarios for use in infrastructure planning studies in the coming year. The assumptions include demand, supply, and system infrastructure elements, including likely portfolios of renewable resources. Based on the process alignment achieved to date and the progress in developing common planning assumptions, California ISO anticipates an orderly identification of system and local needs on the transmission grid resulting from implementation of California's environmental policies and the CPP.

#### *Short- and Mid-Term Resource Adequacy Program*

In addition to planning to ensure that adequate capacity resources will be available on a long time horizon in the LTPP process, the CPUC monitors and enforces requirements that CPUC-jurisdictional LSEs procure capacity and have contracted with adequate specific resources on a year-ahead and monthly basis to ensure that capacity is available to the California ISO when and where needed to serve load. As in long-term planning, the CPUC's RA program now contains system, local, and flexible RA requirements. System requirements are determined based on each LSE's demand forecast plus a 15 percent planning reserve margin. Local requirements are determined based on an annual California ISO study using a 1-in-10 weather year and assuming N-1-1 contingency (i.e., the loss of a large transmission element or generator, followed by the loss of a second element or generator). Flexible requirements are based on an annual California ISO study that calculates largest three hour ramp expected for each month in the upcoming year and bases the requirement on the expected flexible capacity needed to run the system reliably.

The Cap and Trade Regulation, like the Federal Plan, does not have an explicit reliability measure. However, it provides ample flexibility, via trading across the economy-wide system, for regulated electric generating unit sources to address their emissions without causing reliability disruptions via sharp operational changes at any particular plant. Implementing the CPP, which is anticipated not to drive reductions beyond those already produced by California's own rules, will not alter these features of the Cap-and-Trade Regulation. Moreover, California reliability managers, including the California ISO, track the effects of California's full suite of power sector regulations, including the Cap-and-Trade System. This careful coordination further supplements the reliability benefits of California's flexible CO<sub>2</sub>e regulations. The California ISO confirmed, in a Declaration filed in appellate court litigation on the CPP, that its robust reliability planning processes are more than sufficient to address issues that may arise.<sup>44</sup>

As U.S. EPA observes in the CPP preamble, flexibility measures in the final rule allow for trading-based platforms for rule compliance, and these approaches are unlikely to raise reliability concerns in the agency's judgment.<sup>45</sup> Such systems allow for "essential [for reliability] units to meet their compliance obligations while generating even at unplanned but reliability-critical levels."<sup>46</sup> U.S. EPA amplifies this analysis in its proposed Federal Plan for the CPP, in which it explains that "the very nature" of trading systems "supports reliability," obviating the need for separate reliability measures.<sup>47</sup> This has been California's experience to date with the Cap-and-Trade Regulation.

### *Real-time Reliability Assurance*

All balancing authorities must maintain a minimum level of operating reserves. In contrast to planning reserves, an operating reserve margin is the generation capacity available to the balancing authority in real time above that needed to meet the forecasted daily peak load. For the BAA to reliably serve load given near-term load forecasting error and the potential for the sudden failure of major system components (large generators and transmission lines), an operating reserve of 7 to 9 percent or more is typically required. The specific value depends upon the composition of the generation resources online, and the size of the largest system component (or largest single contingency).

Some of California's POUs are members of the California ISO such as Pasadena Water and Power and Silicon Valley Power. The POUs that are not members of the California ISO either act as their own balancing authority or are members of other balancing authorities. For example, Los Angeles Department of Water and Power (LADWP) and Imperial Irrigation District (IID) serve as their own balancing authorities. Sacramento Municipal Utility District (SMUD) is a member of Balancing Authority of Northern

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<sup>44</sup> See Declaration of Neil Millar, California ISO, The U.S. Court of Appeals for the District of Columbia Circuit, Case No. 15-1363 (and consolidated cases), December 1, 2015.

<sup>45</sup> See, for example, 80 Fed. Reg. at 64,879.

<sup>46</sup> *Ibid.*

<sup>47</sup> See 80 Fed. Reg. 64,966 at 64,982 (Oct. 23, 2015)

California along with Roseville Electric and Redding Electric Utility. For the purpose of ensuring reliability, all balancing authorities in California are required to meet reliability standards set by the North American Electric Reliability Corporation (NERC) and the Western Electric Coordinating Council (WECC).

NERC defines the reliability requirements for planning and operating the North American bulk power system. They use a results-based approach focused on performance, risk management and entity capabilities. NERC employs the Reliability Functional Model to determine the functions that need to be performed to ensure the bulk power system operates reliably and is the foundation upon which their reliability standards are based. NERC produces a reliability assessment and performance analysis that identifies potential areas of concern, which is a high-level assessment of resource adequacy. This includes an overview of projected electricity demand growth and generation and transmission additions.

NERC also identifies trends and emerging issues that do not necessarily pose an immediate threat to reliability but that will influence future bulk system planning, development and system analysis. Despite all the focus on reliability, unanticipated contingencies or emergencies can cause outages or disruptions on the bulk power grid. For example, on a very hot summer day when air conditioners are running at full blast, a fire can cause a transmission line outage that threatens reliability or in the worst case results in outages. NERC conducts analysis of these infrequent system events to determine their causes and assure tracking of corrective actions to prevent recurrence and provide lessons learned to the industry.

WECC conducts a number of reliability related activities to help entities throughout the western interconnected grid to carry out their reliability responsibilities. WECC develops and implements regional reliability standards and regional criteria for the Western Interconnection and participates in NERC reliability standards development process. WECC conducts a variety of studies and assessments for the reliable planning and operation of the Bulk Electric System in the Western Interconnection. WECC identifies future transmissions system needs under a variety of possible energy futures for use in long-term planning, and collects and disseminates loads and resources data, direct studies assessing resource adequacy within the Western Interconnection, and addresses the loads and resources activities at NERC.

## 8.2 Generation Reserves Assessment

A reserve margin is a measurement intended to indicate whether electricity supplies are adequate to meet peak system loads. The measurement for the CPP analysis is calculated as the percentage by which available capacity (total of generation capacity not forced out or out for maintenance and demand resources) and import capacity exceed the demand in the state during the coincident peak hour.<sup>48</sup>

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<sup>48</sup> For California this is defined as maximum capacity of a unit during typical summer seasonal peak conditions less the unit's capability used for station service or auxiliaries.

These simulated reserves provide an indication as to the robustness of the system given a particular range of possible system fluctuations, unplanned outages, and unexpected emergencies. It has historically been set so that loss of load would occur no more frequently than one day in 10 years for a 1-in-2 peak demand, translating to a 15 to 17 percent reserve margin. The reserve margin approach entails constructing a fairly straight forward capacity supply and demand balance for the state. The table below shows the reserve margins for the two cases.

Generation reserve margins during the 2027-2031 extrapolation time horizons are assumed to settle towards the 15%-17% industry average.

**Table 13: 2026 Statewide Reserve Margin Estimate**

	Reference Case	Stress Case
Statewide Peak Demand	58,846 MW	63,140 MW
Available In-State Capacity at Peak	60,417 MW	61,461 MW
Imports at Peak	8,602 MW	9,922 MW
Statewide Simulated Reserves	17.3%	13.1%

Source: California Energy Commission, Supply Analysis Office

### 8.3 Consultation to Date

ARB and Energy Commission Staff have repeatedly consulted with state Balancing Authority Area (BAAs) staff in developing this Proposed Plan. Staff contacted representatives from the following BAAs and BAA representatives:

The Balancing Authority of Northern California (BANC), California Independent System Operator (CAISO), Imperial Irrigation District (IID), The Los Angeles Department of Water and Power (LADWP), The Northern California Power Agency (NCPA), the Southern California Public Power Authority (SCPPA), and the Turlock Irrigation District (TID).

Staff shared initial analysis and an overview of the CPP’s requirements and likely Proposed Plan with these representatives via conference call on October 23, 2015, and solicited input. After further plan development, and the construction of the analysis discussed above, staff shared these draft results via webinar with representatives of the above organizations on April 29, 2016. Staff received generally positive feedback at these meetings, and did not receive critical comments or reliability concerns.

This Proposed Plan will be shared with the BAA representatives upon its release, and ARB is seeking feedback from these organizations. ARB staff will address any reliability concerns raised through this consultative process before offering the Proposed Plan for final approval.

## **9. Programmatic Milestones**

The CPP requires the state to identify its progress against “programmatic milestones” in its state reporting and timeline. (See 40 C.F.R. §§ 60.5740(a)(5)(i) & 60.5870(c)(2)). Backstops may be triggered if identified milestones are not met. (See 40 C.F.R. § 60.5740(a)(3)(i)(A)). Such milestones are defined as the “implementation of measures necessary for plan progress, including specific dates associated with such implementation.” (40 C.F.R. § 60.5880).

ARB staff are proposing that all regulatory measures required to implement this Proposed Plan be implemented well before the CPP compliance dates, if approved by the Air Resources Board. Accordingly, ARB staff propose a single programmatic milestone: The finalization of regulations implementing this Proposed Plan as part of the MRR and Cap-and-Trade Regulation. This milestone must be met by the CPP’s implementation date, January 1, 2022, and the implementing regulations must remain in force thereafter.

## **10. Legal Authority**

The CPP requires states to demonstrate that they have legal authority and funding to implement and enforce compliance plans. (See 40 C.F.R. § 60.5745(a)(9)). ARB has extensive authority to implement this Proposed Plan. Relevant statutes are attached as supporting materials in Appendix H.

### *Authority to Develop Federal Clean Air Act Compliance Plans and to Promulgate Regulations*

ARB has extensive authority to regulate and plan for compliance with federal Clean Air Act requirements. By statute, ARB is “designated as the air pollution control agency for all purposes set forth in federal law,” which includes compliance with section 111(d) of the Act, and emission guidelines promulgated under that section. (See Health & Safety Code § 39602). ARB is empowered to conduct all acts “as may be necessary for the proper execution of its duties,” including adopting rules and regulations. (Health & Safety Code §§ 39600, 39601). ARB is also empowered to gather information on air pollutants and their sources. (Health and Safety Code § 39607). These and related authorities, as well as greenhouse gas-specific authorities discussed below, provide ARB with ample authority to develop and approve this Proposed Plan.

### *Authority to Implement the Mandatory Reporting Regulation*

In addition to its general authorities, ARB has been directed to develop regulations “to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program.” (Health & Safety Code § 38530). That statute goes on to require that ARB account specifically for “greenhouse gas emissions from all electricity consumed in the state” and to do so via requiring “monitoring and annual reporting” of these greenhouse gases. (Health & Safety Code §

38530(b)). ARB is empowered to ensure that these reports are verified, that they are rigorously accounted for, and that comprehensive supporting records are maintained. (*Id.*). ARB is further directed to periodically review and update requirements as necessary. (Health & Safety Code § 38530(c)). These authorities support MRR, and provide ample support to review and update that regulation to ensure that CPP reporting requirements are also fulfilled.

### *Authority to Implement the Cap-and-Trade Regulation*

ARB is designated as the state agency “charged with monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases.” (Health & Safety Code § 38510). It is further empowered to adopt “rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions” from covered sources. (Health & Safety Code § 38560). ARB is directed to, at a minimum, reduce statewide greenhouse gas emissions to 1990 levels by 2020 (Health & Safety Code § 38551), to “maintain and continue” reductions beyond 2020, and to regulate as necessary to further these purposes. (Health & Safety Code §§38551(b), 38562(a), (g)). A market-based compliance mechanism, such as the Cap-and-Trade Regulation, is specifically authorized (Health & Safety Code §§ 38570, 38562(c) (including specification of initial compliance periods)).

Accordingly, ARB is authorized to maintain statewide greenhouse gas reductions, and to continue to regulate to ensure that statewide greenhouse gas limit is maintained, as well as to pursue further reductions. It is also authorized to do so using a market-based compliance mechanism, such as the Cap-and-Trade Regulation. Importantly, ARB authority to maintain the cap, alone, would support CPP compliance under this Proposed Plan, as the modeling results above demonstrate; further emissions reductions authority will further support compliance. This authority, coupled with ARB’s authority to develop regulations and to take other actions to comply with federal Clean Air Act mandates, supports ARB’s use of the Cap-and-Trade Regulation within this state measures Proposed Plan.

### *Funding*

ARB receives funding from many sources. To support its greenhouse gas control work, ARB is specifically authorized to adopt a “schedule of fees to be paid by the sources of greenhouse gas emissions” it regulates in order to further the greenhouse gas regulatory purposes with which ARB was charged by AB 32. (Health & Safety Code § 38597). ARB has adopted such a fee schedule, the AB 32 Cost of Implementation Fee Regulation (17 CCR §§95201 *et seq.*). Under that regulation, ARB determines the annual “total required revenue” for its permitted purposes (see 17 CCR §95203(a)), and apportions a fee obligation to make up this revenue amongst a group of high-emitting regulated entities (see 17 CCR §95203(k)). This mechanism assures that ARB will have continued funding to operate greenhouse gas reduction programs, including those used to comply with the CPP under this Proposed Plan. Further, ARB supports efforts by the



federal government to expand grant funding under section 105 of the federal Clean Air Act to further support state implementation efforts. (See 42 U.S.C. § 7405).

## **11. Public Process and Engagement with Disadvantaged Communities**

The CPP requires that plans be submitted with documentation of public participation, including documentation of “any conducted community outreach and community involvement, including engagement with vulnerable communities.” (40 C.F.R. § 60.5745(a)(12)). Submitted plans must also include certifications that a public hearing was held, along with documentation of witnesses and a brief summary of public submissions. (40 C.F.R. §§ 60.23 & 60.5745(a)(11)). This section addresses those requirements

### *Community Outreach, Including Engagement with Vulnerable Communities*

ARB staff has conducted, and will continue to conduct, substantial outreach to communities throughout California.

#### *General Public Outreach*

General outreach has included regular public workshops, announced via public notices, website postings, and newspaper notices throughout the development of this Proposed Plan. ARB has regularly offered Spanish-language translation at its workshops. The first of these workshops was conducted on September 9, 2014, to discuss U.S. EPA’s proposed Clean Power Plan and ARB’s potential comments on that proposal. The second was conducted on October 2, 2015, to share a white paper documenting ARB’s initial thinking on CPP compliance options. For each workshop, the public was offered an opportunity to submit feedback, and did so.<sup>49</sup>

After the October 2, 2015 workshop, ARB staff provided an informational update to the Air Resources Board members at a public meeting, held on November 19, 2015. Public feedback was invited at the Board meeting as well.

ARB staff then held a full-day workshop to discuss plan design options, modeling design, and issues related to the Cap-and-Trade Regulation as a CPP compliance tool on December 14, 2015, and again solicited and received public feedback. Taking this feedback into account, staff released a second white paper specifically addressing the use of the Cap-and-Trade Regulation in this Proposed Plan and held a workshop to discuss these options on February 24, 2016, again soliciting feedback.

This public process has shaped this Proposed Plan. A complete record of these workshops, including dockets listing public feedback letters, and the relevant ARB white papers and slide presentations, is attached as Appendix I.

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<sup>49</sup> A record of public workshops and feedback is posted at <http://www.arb.ca.gov/cc/powerplants/powerplants.htm>.

## *Outreach to Vulnerable Communities and Steps Taken to Address Potential Impacts*

In addition to the open and extensive public feedback process, ARB staff has conducted specific outreach to vulnerable communities, and will continue to do so.

ARB's AB 32 Environmental Justice Advisory Committee (EJAC) was established by statute to address environmental justice issues associated with greenhouse gas regulations developed under AB 32. EJAC is "comprised of representatives from communities in the state with the most significant exposure to air pollution, including, but not limited to, communities with minority populations or low-income populations, or both." (Health & Safety Code § 38591). ARB staff regularly consult EJAC on greenhouse gas regulatory matters.<sup>50</sup>

ARB staff presented on the CPP and compliance plan options to the EJAC on December 7, 2015 and solicited EJAC advice on the structure of the compliance plan and on ways to further support outreach to vulnerable communities.<sup>51</sup> EJAC members offered their impressions. On March 11, 2016, ARB staff provided a further, in-depth, overview of the CPP to EJAC members, and again invited feedback and advice.<sup>52</sup>

EJAC members and ARB staff have identified a need for continued outreach to vulnerable communities. This Proposed Plan will be forwarded, therefore, to the EJAC, and to other representatives of vulnerable communities that ARB staff or the EJAC may identify; these representatives and other community members will be encouraged to submit comments about any of their concerns. ARB staff also is exploring public workshops accessible to members of vulnerable communities on the Proposed Plan after it has been issued.

In addition to this procedural effort, ARB is engaged in an extensive adaptive management effort to ensure that any potential impacts that may result from the implementation of the Cap-and-Trade Regulation are identified and appropriately addressed using a transparent process. This Adaptive Management Program has been identified by U.S. EPA as a model for other states in the CPP. (See 80 Fed. Reg. at 64,919). ARB staff continue to implement and improve this program.<sup>53</sup>

### *Tribal Communication*

ARB has also engaged in communications to the sovereign tribal governments of California. In addition to addressing comments and questions from staff members of these governments, ARB staff meet with California EPA's Tribal Advisory Committee in

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<sup>50</sup> More information on the EJAC can be found at <http://www.arb.ca.gov/cc/ejac/ejac.htm>.

<sup>51</sup> The presentation is available at:

[http://www.arb.ca.gov/cc/ejac/meetings/120715/arb\\_combined\\_slides.pdf](http://www.arb.ca.gov/cc/ejac/meetings/120715/arb_combined_slides.pdf)

<sup>52</sup> The presentation is available at [http://www.arb.ca.gov/cc/ejac/meetings/040416/cpp\\_march2016.pdf](http://www.arb.ca.gov/cc/ejac/meetings/040416/cpp_march2016.pdf).

<sup>53</sup> For more information on the Adaptive Management Program, see

<http://www.arb.ca.gov/cc/capandtrade/adaptivemanagement/adaptivemanagement.htm>.

March 2016<sup>54</sup> to share information on the CPP and Proposed Plan. Staff invited members of that committee to request additional information if desired and will respond to any requests.

### Anticipated Process Going Forward

Staff will present this Proposed Plan to the Board at its September 2016 hearing. At the hearing, the Board may provide staff further direction, but will not take final action on the Proposed Plan. As appropriate, thereafter, staff may conduct further comment periods, in coordination with any public processes appropriate for the amendments to the Cap-and-Trade Regulation and MRR. Staff anticipates presenting a final plan to the Board in spring 2017, with submission to U.S. EPA (if approved) thereafter.

### Compliance with Certification Requirements

The CPP and U.S. EPA's general regulations for state plan submittals require that noticed public hearings be held on proposed compliance plans and that the state certify that such hearings have been held. (See 40 C.F.R. § 60.5745(a)(11)). Hearings must be held with at least thirty days' notice to all interested parties. (See 40 C.F.R. § 60.23).

In addition to the extensive public workshops that ARB has held to date, this Proposed Plan is being released with a hearing notice providing 45 days' notice prior to the first of two ARB Board hearings on the Proposed Plan and related regulatory amendments. The notice and a certification as to that hearing will be included in the final plan submittal, along with a summary of public comments and required witness lists as provided for in the regulations. Consistent with 40 C.F.R. § 60.23, this Proposed Plan and supporting materials are being made available, via the internet, in all affected regions. Notice is along being provided to the public and all parties listed 40 C.F.R. § 60.23 via a variety of means, including newspaper publications and internet and listserv notices.

## **12. Environmental Analysis**

The Air Resources Board (ARB), as the lead agency for the Proposed Plan has prepared an environmental analysis under its certified regulatory program (17 CCR 60000 – 60008) to comply with the requirements of the California Environmental Quality Act (CEQA). ARB's regulatory program, which involves the adoption, approval, amendment, or repeal of standards, rules, regulations, or plans for the protection and enhancement of the State's ambient air quality has been certified by the California Secretary for Natural Resources under Public Resources Code section 21080.5 of CEQA (14 CCR 15251(d)). ARB, as a lead agency, prepares a substitute environmental document (referred to as an "Environmental Analysis" or "EA") as part of the Staff Report to comply with CEQA (17 CCR 60005).

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<sup>54</sup> For more information on the Tribal Advisory Committee, see <http://www.calepa.ca.gov/Tribal/Committee/default.htm>.

The Draft Environmental Analysis (EA) for the Proposed Plan is included in Appendix J to this document. The Draft EA provides a single coordinated programmatic environmental analysis of an illustrative, reasonably foreseeable compliance scenario that could result from implementation of the proposed Clean Power Plan (CPP) Compliance Plan and amendments to the Cap-and-Trade Regulation. The proposed CPP Compliance Plan and Cap-and-Trade regulation have two separate notices and staff reports and will be considered by the Board in separate proceedings. This approach is consistent with CEQA's requirement that an agency consider the whole of an action when it assesses a project's environmental effects, even if the project consists of separate approvals (Cal. Code Regs., tit. 14, § 15378(a)).

The Draft EA provides an environmental analysis which focuses on reasonably foreseeable potentially significant adverse and beneficial impacts on the physical environment resulting from reasonably foreseeable compliance responses taken in response to implementation of the proposed actions within the Proposed Plan. The Draft EA is intended to disclose potential adverse impacts and identify potential mitigation specific to the Proposed Plan. The Draft EA has been prepared as a joint document for this Proposed Plan and for amendments to the Cap-and-Trade Regulation because the projects are closely related. Accordingly, it discusses environmental impacts associated with both actions. Many of the adverse impacts identified are, in fact, consequences of operation of the proposed Cap-and-Trade Regulation as a whole, rather than of the Proposed Plan and CPP compliance specifically.

For the purpose of determining whether the Proposed Plan would have a potential adverse effect on the environment, ARB evaluated the potential physical changes to the environment resulting from implementation of the proposed plan. Implementation of the Proposed Plan would require all CPP affected EGUs to comply with the Cap-and-Trade Regulation so long as they are subject to the CPP and the requirements of the Regulation; alignment of some program deadlines and compliance periods between the CPP and the Cap-and-Trade Regulation, to ensure that affected EGUs comply with CPP deadlines; and backstop provisions, triggered if affected EGU emissions, on a statewide basis, exceed required federal targets in any compliance period by more than 10 percent.

The Draft EA states that implementation of the Proposed Plan (and Cap-and-Trade Regulation) could result in the following short-term and long-term beneficial and adverse impacts: beneficial short-term and long-term impacts to energy demand and greenhouse gases; less-than-significant impacts to aesthetics, agriculture and forest resources, geology, soils, and mineral resources, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, population employment, and housing, public services, recreation, transportation and traffic and utilities and service systems; and potentially significant and unavoidable adverse impacts to aesthetics, agriculture and forest resources, air quality, biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, recreation, and transportation/traffic.

The potentially significant and unavoidable adverse impacts are primarily related to short-term, construction-related activities and implementation of offset projects that are reasonably foreseeable as a result of the proposed amendments to the Cap-and-Trade Regulation. This explains why some resource areas are identified above as having both less-than-significant impacts and potentially significant impacts. Please refer to the Draft EA for further details.

Written comments on the Draft EA will be accepted starting August 5, 2016, through 5 p.m. on September 19, 2016. The Board will consider the Final EA and responses to comments received on the Draft EA before considering adoption of the Proposed Plan.

### **13. Supporting Materials**

Extensive supporting materials are included as appendices to this Proposed Plan, pursuant to 40 C.F.R. § 60.5745(a)(13). The appendices are as follows:

- Appendix A: List of Affected EGUs
- Appendix B: Documentation of Communications with California EGUs
- Appendix C: Target Recalculation Calculations
- Appendix D: Text of Proposed Emissions Standards and State Measures
- Appendix E: Documentation of Modeling Assumptions
  - Appendix E1: Detailed annual energy and emissions results for Reference Case and Stress Case
  - Appendices E2a and E2b: Summary of unit operating characteristics including: annual generation, CO<sub>2</sub>e emissions, fuel use, heat rates, capacity and capacity factors
  - Appendix E3: Natural gas burner tip prices
  - Appendix E4: Coal prices
  - Appendix E5: Wholesale electricity prices
- Appendix F: Summary and Text of SB 350 (Statutes of 2015, De Leon)
- Appendix G: Documentation for the Compliance Instrument Tracking System Service
- Appendix H: Relevant Legal Authorities
- Appendix I: Record of Public Participation and Outreach
- Appendix J: Draft Environmental Analysis