

August 8, 2014

**Comments of the Independent Energy Producers Association on the
Proposed Amendments to the AB 32 Cost of
Implementation Fee Regulation
(Released July 29, 2014)**

The Independent Energy Producers Association (IEP) submits these comments on the Proposed Amendments to the AB 32 Cost of Implementation Fee Regulation (released July 29, 2014). IEP also submitted nearly identical comments on the Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, also released July 29, 2014. Given that staff's proposal is "to amend the Fee Regulation to more closely align the Fee Regulation with the MRR and the Cap-and-Trade provisions...and to ensure fee payer equity", it is appropriate to submit these comments in this amendment process as well.¹

IEP's comments focus the need to amend (or at least re-assess) the current and proposed methodology for imputing emissions associated with so-called "Unspecified Imports." IEP is concerned that there are no amendments proposed related to the re-calculating of the default emissions factor for unspecified electricity imports. Proposed Section 95203(e)(2) of the Cost of Implementation Fee Regulation actually addresses the default emission factor for unspecified sources; however, this section reverts back to the same emission factor 0.428MTCO₂e/MWh that is currently being used under the Mandatory Reporting Regulations.

Last year, IEP commissioned a study by Atkins on this matter.² We submitted this study for review during the 2013 Mandatory Reporting Amendment Process.³ Moreover, a number of academics raised concerns about "resource shuffling" and the impact on energy/carbon markets and accurate accounting of emission reductions.⁴

Recently, IEP commissioned Atkins to update its study. Attached for your review and assessment is the new, updated Atkins study: "Greenhouse Gas Emissions of Imported Electricity Updated Assessment," July 2014. Similar to the methodology Atkins employed in 2013, the update study focuses on the Arizona Public Service Company (APS) as a point of

¹ See Notice of Public Hearing to Consider Amendments to the Cost of Implementation Fee Regulation, Released July 29, page 2.

² See Atkins, "Greenhouse Gas Emissions Assessment of Imported Power," October 18, 2013.

³ See Comments of the Independent Energy Producers Association on the Staff Report: Initial Statement of Reasons for Rulemaking Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Filed October 22, 2013, available at: <http://www.arb.ca.gov/lists/com-attach/35-ghg2013-B24BYIYnAAwCZ1U6.pdf>

⁴ See James Bushnell, Yihsu Chen, and Matthew Zaragoza-Watkins (2013), Downstream Regulation of CO₂ Emissions in California's Electricity Sector. Energy Institute at Haas Working Paper #236, available at: http://ei.haas.berkeley.edu/pdf/working_papers/WP236.pdf.; See Danny Cullenward and David Weiskopf (2013), Resource Shuffling and the California Carbon Market. Stanford Law School Environmental and Natural Resources Law & Policy Working Paper; See Comments of Danny Cullenward on CARB's Proposed Amendments to the California Cap-and-Trade Program (October 2013).

comparison due to its close proximity to California for purposes of exporting into California. Notably, APS informed the marketplace on May 13, 2013 that "... any power that is sold from APS has been generated by the APS power system and not specifically by a specific generating resource."⁵ As a result, APS exports into California would be imputed an emissions factor based solely on the methodology adopted by the Air Resources Board (ARB) for unspecified imported power.

Importantly, the updated Atkins study concludes the following:

- The emission rates associated with each of the APS portfolio's assumed to supply the power for export to California, for both 2010 and 2014, exceed the ARB default emission rate for unspecified electricity imports of 0.428 MTCO₂e/MWh; often, by a wide margin. For example, the projected 2014 APS portfolio exceeds the default emissions rate by 19% when assessing the emissions from the total APS portfolio; and, it exceeds the default emissions rate by 93% when assessing an APS portfolio that assumes the low-cost, carbon free nuclear and renewable power serves native load.
- A comparison of the APS emission rates between 2009 and 2010 indicates no significant reduction of emissions in the APS system. Moreover, when looking at their integrated resource plans for the future, APS appears committed to a business plan through 2029 that is unlikely to realize significant reductions in carbon emissions from their overall portfolio.
- The competitive advantage realized by APS due to their ability to take advantage of a favorable default emissions factor not available to in-state California generators is significant:
 - The May 2014 carbon allowance auction cleared at \$11.34 per allowance. The Atkins study indicates that APS may have avoided \$25 to \$76 million in carbon costs *in 2014*, depending on which resources in their portfolio are identified as "unspecified power" imports to California.
 - Assuming carbon allowances were to clear at \$15.60 per allowance; APS may avoid \$34 million to \$105 million in carbon costs *in 2014* depending on which types of resources in their portfolio are defined as unspecified power imports to California.
 - Avoidance of this operating cost has a material effect on generators participating in energy markets in California and the west. Currently, the cost of mitigating a ton of carbon emissions (i.e. the allowance cost) is reported to be approximately 6 mills/kWh, which is enough to effect the dispatch order of generation serving load in California and, perhaps, elsewhere.

This round of amendments provides a suitable and needed opportunity to re-consider the current methodology for imputing emissions to unspecified imports. The evidence above demonstrates that the methodology for imputing emissions associated with unspecified imports may be shielding accurate emissions accounting and reporting thereby exacerbating inefficiencies and inequities in the current program design. This may potentially contribute to resource shuffling and GHG emissions "leakage," which undermines the CARB's intent to reduce GHG emissions today and in the near future. Furthermore, to the extent that the allocation of the cost of the Implementation Fee is based on that same accounting mechanism, then the inequities that exist today will continue to persist and undermine the integrity of the AB 32 program generally and the C&T Program specifically.

⁵ APS Communication re California Cap-and-Trade Resource Shuffling Concerns, dated May 8, 2013.

These amendments present an appropriate opportunity, in advance of the significant expansion of the C&T Program beginning January 1, 2015, to revisit the methodology for imputing emissions associated with unspecified imports. Accordingly, IEP recommends that CARB take this opportunity to revisit and revise the current methodology for imputing emissions to unspecified imported power. In reviewing the current methodology, the goal should be to derive a methodology that accurately reflects the "pool of power" imported into California under the label of Unspecified Imports. It would be ideal for the CARB to adopt a new methodology, which would reflect a more accurate default emissions factor, by December 31, 2014, to be applicable to the 2015 compliance period.

Respectfully Submitted,



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Attachment 1

Greenhouse Gas Emissions of Imported Electricity Updated Assessment

July 2014

Prepared by



Summary

This paper is an Update to the *Assessment of Greenhouse Gas (GHG) Emissions from Imported Electricity*, which was completed by Atkins in October of 2013. These assessments use publicly-available data to develop a set of emission rates for a non-California entity under a variety of generation scenarios, for comparison with the California Air Resources Board's (ARB) default emission factor for unspecified electricity imports of 0.428 metric tons of carbon dioxide equivalent per megawatt hour (MTCO₂e/MWh) under the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

Arizona Public Service Company (APS) was used as a point of comparison in these assessments because of the utility's proximity to California and connectivity within the electric grid. Both the Initial Assessment and Updated Assessment of APS's generation scenarios used data from the U.S. Environmental Protection Agency's (EPA) Emissions & Generation Resource Integrated Database (eGRID), with adjustments to calculations based on APS's 2012 and 2014 Integrated Resource Plans. This Updated Assessment resulted in a range of six emission factors ranging from 0.5076 MTCO₂e/MWh to 0.8247 MTCO₂e/MWh for 2010 and 2014. An additional emission factor of 0.8445 MT/CO₂e for the 2010 APS Power Control Area (PCA) is included as an upper-bound of the estimates.

The entire range of emission rates calculated for both 2010 and 2014 are above the ARB default emission rate for unspecified electricity imports of 0.428 MTCO₂e/MWh. A comparison of 2009 emission rates computed using eGRID data in the Initial Assessment and 2010 emission rates computed using eGRID data in this Updated Assessment does not indicate significant reduction of emissions in the APS system over one year. While the comparison of 2010 emission rates with the 2014 projected emission rates suggests modest GHG emission reductions, APS appears focused on a business-as-usual trajectory for its planning horizon out to 2029, and therefore significant GHG emission reductions are unlikely over time.

The potential costs of unreported unspecified resources were calculated using reserve price of the most recent cap-and-trade auction in May of 2014, as well as the mean price of the first cap-and-trade auction, which took place in November of 2012. Assuming an allowance price of \$11.34 per allowance (MTCO_{2e}), APS is in a position to avoid between \$25 million and \$76 million in allowance costs by not reporting resources above the default emission rate. Assuming an allowance price of \$15.60 per allowance, APS could be in a position to avoid between \$34 million and \$105 million per year in allowances purchases. This level of avoided allowance costs creates a competitive advantage for out of state electric power entities and may reduce demand for allowances, artificially depressing market prices.

Updated Assessment Generation Scenarios	2010 emission rates (MTCO _{2e} /MWh)	2010 percentage above ARB default emission rate	2010 costs above default emission rate (\$11.34/MT)	2010 costs above default emission rate (\$15.60/MT)	2014 emission rates (MTCO _{2e} /MWh)	2014 percentage above ARB default emission rate	2014 costs above default emission rate (\$11.34/MT)	2014 costs above default emission rate (\$15.60/MT)
Total APS	0.5332	25%	\$32 million	\$44 million	0.5076	19%	\$25 million	\$34 million
APS excluding nuclear	0.8027	88%	\$76 million	\$104 million	0.7333	71%	\$66 million	\$91 million
APS excluding nuclear and renewable	0.8087	89%	\$76 million	\$105 million	0.8247	93%	\$76 million	\$105 million

Table S1. Summary of findings of the Updated Assessment.

Objectives of the Assessment

In order to compare an out-of-state entity's actual GHG emission rate to GHG emissions reported to the ARB using the default emission factor for unspecified electricity imports of 0.428 MTCO_{2e}/MWh, this assessment used publicly-available data to develop a set of emission rates for APS, as an example of a non-California entity.

The objective of this analysis was to calculate emission rates for APS using three generation scenarios:

1. APS's entire generation portfolio,
2. APS's generation portfolio excluding nuclear energy, and
3. APS's generation portfolio excluding nuclear and renewable energy.

Due to the availability of data, this study looked at these three generation scenarios for both 2010 and 2014. Additionally, it provides an emission rate for the entire APS Power Control Area (PCA), using eGRID, leading to a total of seven emission rates. The Initial Assessment looked

at the same generation scenarios for the years 2009 and 2012, as well as a PCA emission rate for 2009 based on eGRID data.

Description of Data

This assessment relies on data from the EPA's eGRID, a comprehensive inventory of environmental attributes of electric power systems that is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government.¹ The 9th edition of eGRID is a compilation of 2010 data. In order to complete a thorough, objective, and up-to-date assessment of GHG emissions, this analysis used the eGRID for all sources of generation within APS's service territory for the 2010 portfolio, and used APS's 2014 Integrated Resource Plan (IRP) to make adjustments to APS's likely 2014 portfolio based on APS's share of ownership of a number of plants in 2014 and Power Purchase Agreements (PPAs) for a number of renewable resources. The APS 2014 IRP was used as the basis for adding renewable generation to the 2014 generation scenarios.

Plant and Generator Information

The plants listed in Table 1 were included in the eGRID data and therefore used in this Updated Assessment for the 2010 and 2014 generation scenarios. The nameplate capacity of Cholla, Four Corners, Navajo, Yucca, Palo Verde, Snowflake White Mountain, and Salton Sea were revised to reflect the APS-entitled nameplate capacity based on the percent of ownership listed in eGRID and whether the plant was known to have had a PPA in place for before 2010.² In many cases, APS-entitled nameplate capacity was further adjusted for 2014 generation scenarios, based on information the APS 2014 IRP.³ Additional resources included in the 2014 generation scenarios are discussed later in this section.

Special attention was given to Four Corners, both in the Initial Assessment as well as in this Updated Assessment. The adjusted nameplate capacity for Four Corners in the Initial Assessment of Imported Electricity, which examined the 2009 and 2012 portfolios, was 791 MW.⁴ This value was slightly lower than the eGRID data for 2010, which indicated that APS owned 39% of Four Corners in 2010, resulting in an APS-entitled nameplate capacity value of

¹ <http://www.epa.gov/cleanenergy/energy-resources/egrid/faq.html#egrid8>

² PPAs are according to APS's 2014 IRP

³ This analysis conservatively assumed that APS owned the same percentage of each of the plants listed in Table 2 in 2009 as well as in 2012.

⁴ APS 2012 IRP. P. 10.

879 MW. On December 30, 2013, APS purchased Southern California Edison's (SCE) 48% interest in each of Units 4 and 5 of Four Corners, acquiring 739 MW from SCE. As a result of the transaction, APS retired units 1, 2 and 3. The APS 2014 IRP indicates that the 2014 value for APS-entitled nameplate capacity from Four Corners is 970 MW.

In addition, according to eGRID, APS owned 29.1% of the output from the Palo Verde Nuclear Generating Station in 2010, which had a nameplate capacity of 4,209.3 MW and therefore resulted in 1,225 MW of APS-entitled nameplate capacity in 2010. This nameplate capacity is slightly higher than the nameplate capacity used in the Initial Assessment of Imported Electricity, which assumed 1,146 MW of APS-entitled nameplate capacity both for 2009 and 2012. The APS 2014 IRP lists the total nameplate capacity of the plant at 3,937 MW. Atkins used the eGRID data for 2010 (APS-entitled nameplate capacity of 1,225 MW) and the APS 2014 IRP data (1,146 MW) for the calculation of the 2014 emission rate.

Plant name	Plant primary fuel generation category	Plant nameplate capacity (MW) - eGRID	2010 APS-entitled nameplate capacity (MW)	2014 APS-entitled nameplate capacity (MW) - 2014 IRP
<i>Cholla</i>	<i>Coal</i>	<i>1,129</i>	<i>714.76</i>	<i>647</i>
<i>Four Corners</i>	<i>Coal</i>	<i>2,270</i>	<i>878.79</i>	<i>970</i>
<i>Navajo</i>	<i>Coal</i>	<i>2,409</i>	<i>337.30</i>	<i>315</i>
Douglas	Oil	21	21.40	15
Ocotillo	Gas	334	334.00	320
Redhawk	Gas	1,136	1136.00	1,000
Saguaro	Gas	436	435.50	176
Sundance	Gas	450	450.00	410
West Phoenix	Gas	1,207	1206.80	998
<i>Yucca</i>	<i>Gas</i>	<i>386</i>	<i>272.82</i>	<i>233</i>
<i>Palo Verde</i>	<i>Nuclear</i>	<i>4,209</i>	<i>1224.91</i>	<i>1,146</i>
Prescott Airport	Solar PV	2	2.10	NA
<i>Snowflake White Mountain⁵</i>	<i>Biomass</i>	<i>27</i>	<i>10.00</i>	<i>14</i>
<i>Salton Sea⁶</i>	<i>Geothermal</i>	<i>185</i>	<i>10.00</i>	<i>10</i>

Table 1. APS 2010 generation resources included in eGRID data.

⁵ According to [Renergy Holdings](#), APS has a PPA in place to purchase 10 MW of biomass power from Snowflake White Mountain before 2010.

⁶ According to p. 13 of the [APS 2014 IRP](#), APS executed a PPA with CalEnergy to purchase 10 MW of energy from the Salton Sea Geothermal Project in January of 2006.

Excluded Resources

The resources listed below in Table 2 are included in eGRID data as power plants within APS's service territory and PCA; however APS is not named as an owner of any share of the plant and have therefore been excluded from this analysis. Catalyst Paper Snowflake Mill is affiliated with Snowflake White Mountain Biomass, with whom APS has a PPA for 10 MW, however there is no evidence of a PPA with the coal portion of the Snowflake Mill. According to eGRID, Dry Lake Wind I and II are located in APS's service territory and PCA, however further research indicates that Salt River Project purchases 100% of output from Dry Lake I and II through a PPA.⁷

Similarly, with regard to the Yuma Cogeneration gas plant, San Diego Gas & Electric purchases 100% of the power through a PPA with MidAmerican, and Falcon Power is the operator. Gila River Power Station, a 2,476 gas plant, was included in the APS service territory in the 2009 eGRID data, however in the 2010 version; it is listed within the Gila River Power Station LP service territory. Currently Entegra Power Group owns and operates the facility. According to the Entegra website, the Gila River Plant is interconnected to the Arizona power transmission network through two 500 kV ties and one 230 kV tie, both of which "provide access to energy markets throughout the southwest and allow the plant to sell power to serve the needs of the Arizona, New Mexico, southern Nevada, and southern California markets."⁸ As such, none of the resources discussed above and described in Table 2 are included in this Updated Assessment.

Plant name	Plant primary fuel generation category	Plant nameplate capacity (MW) - eGRID
Catalyst Paper Snowflake Mill	Coal	70.50
Dry Lake Wind II LLC	Wind	65.10
Dry Lake Wind LLC	Wind	63.00
Yuma Cogeneration Associates	Gas	62.60
Gila River Power Station	Gas	2,476.0

Table 2. eGRID resources excluded from the analysis.

Addition of New Resources for the 2014 Portfolios

The 2014 generation scenarios included the addition of resources listed below in Table 3. These resources are all described in the APS 2014 IRP. The 2.1 MW Prescott Airport Solar

⁷ <http://www.srpnet.com/about/stations/drylakewind.aspx>

⁸ <http://www.entegraperpower.com/Gila.htm>

Project was deleted from the 2010 generation sources and replaced with the 10 MW SunEdison Prescott Solar Plant for the 2014 generation scenarios.

Plant name	Plant primary fuel generation category	2014 APS-entitled nameplate capacity (MW) - 2014 IRP
Paloma Solar	Solar PV	17
Cotton Center	Solar PV	17
Hyder Solar	Solar PV	16
Hyder II Solar	Solar PV	14
Chino Valley	Solar PV	19
Foothills Plant	Solar PV	35
*Ajo Project	Solar PV	5
*SunEdison Prescott Project	Solar PV	10
*Saddle Mountain	Solar PV	15
*PSEG Badger-Desert Sky	Solar PV	15
*RE Gillespie	Solar PV	15
*Solana	CSP + TES	270
*Aragonne Mesa Wind Project	Wind	90
*High Lonesome Wind Project	Wind	100
*Perrin Ranch Wind Project	Wind	99
*Glendale Biogas Project	Biogas	3
*NW Regional Biogas Project	Biogas	3

Table 3. Additional APS 2014 generation resources.

Treatment of Power Purchase Agreements

The APS 2014 IRP indicates an additional 2,460 MW of PPAs for conventional resources, which are not included in this assessment given a lack of data with regard to the fuel generation categories, capacity factors, emissions, and annual net generation. However, PPAs are included for 649 MW of renewable generation in 2014, due to the availability of details on these agreements in the APS 2014 IRP. It is worth noting that PPAs make up for 85% of the 767 MW of renewable resources included in the APS 2014 IRP. The inclusion of PPAs for renewable resources but not conventional resources in 2014 in this Updated Assessment will result in an extremely conservative APS portfolio emission rate for 2014, meaning that it will be significantly lower than the actual value due to the exclusion of conventional PPAs. To give some indication of the total APS portfolio of owned and operated generation, Atkins did analyze one generation

scenario without consideration of any PPAs (renewable or conventional), which is included in the final table of the Appendix.

Power Control Area Data

The eGRID also categorizes generation by individual PCAs, which are described as “smaller regions of the power grid in which all power plants are centrally dispatched”.⁹ This breakdown of data includes many of the plants listed in Table 1, and provides aggregated values for annual net generation (MWh) and annual CO₂ equivalent emissions (tons); the two values from which an emission rate can be calculated. The plants included in APS’s PCA in the eGRID are listed below in Table 4. The PCA data fully attributes all generation and emissions of the various power plants to APS, without adjusting for partial ownership as Atkins did in this Assessment. As Table 4 indicates, the PCA data does not include generation from the Navajo Power Plant (coal) or the Palo Verde Nuclear Generating Station, even though APS owns portions of both plants. The PCA calculation does include generation from Catalyst Paper Snowflake Mill and Yuma Cogeneration Associates, both of which were excluded from this Updated Assessment.

APS PCA Plants
Catalyst Paper Snowflake Mill
Cholla
Douglas
Dry Lake Wind II LLC
Dry Lake Wind LLC
Ocotillo
Prescott Airport
Red Hawk
Saguaro
Snowflake White Mountain Power LLC
Sundance
West Phoenix
Yucca
Yuma Cogeneration Associates
Four Corners

Table 4. Power plants within the APS PCA.

Assumptions and Methodology

Annual Net Generation Calculations

To calculate annual net generation for the adjusted plants and generators in Table 1 for the 2010 generation scenarios, this analysis applied the capacity factors provided for the various

⁹ <http://www.epa.gov/cleanenergy/energy-resources/egrid/faq.html#egrid3>

plants in eGRID to the adjusted nameplate capacity values to determine the APS-entitled annual net generation.

Renewable resource	Capacity factor
Commercial and industrial solar PV	21%
Parabolic trough, salt storage	41%
Arizona wind ¹⁰	23%
Geothermal ¹¹	96%
Biogas	88%
Biomass	85%

Table 5. Capacity factor assumptions from the APS 2014 IRP.

For a number of generation resources in the 2014 portfolios, however, it was necessary to assume a capacity factor for various renewable resources in order to estimate the annual net generation from specific resources mentioned in the APS 2014 IRP but not included in the eGRID data.¹² In these instances, Atkins used the capacity factors from the APS 2014 IRP.¹³ The assumed capacity factors for renewable resources are listed above in Table 5.

Annual CO₂ Equivalent Emissions

For the 2014 generation scenarios, one additional calculation was necessary to determine the emissions associated with renewable generation; in particular, geothermal and biomass/biogas. This analysis used an emission rate of .0272 MTCO₂e/MWh for the Salton Sea Geothermal Project, which was based on 2010 generation and emissions data from eGRID.¹⁴ This analysis also assumed an emission rate of 0.00 MTCO₂e/MWh for the Glendale Biogas Project, based on the emission rate provided in the eGRID data for all other landfill gas plants.

In order to obtain the annual CO₂ equivalent emissions for the 2010 adjusted generation, this Assessment relied on the annual CO₂ equivalent emission rates associated with the plants provided in the eGRID, and applied them to the revised annual net generation values. In other words, the total adjusted annual emissions of all plants (MTCO₂e) were divided by the total

¹⁰ The Arizona wind capacity factor estimate was also used for wind PPAs from New Mexico.

¹¹ The 2014 generation scenarios used the estimated capacity factor from the APS 2014 IRP (96%), rather than the actual eGRID data for the Salton Sea Geothermal Project, as an estimate. The 2010 eGRID capacity factor for the Salton Sea Geothermal Project was an average of 83% for Units 1-5.

¹² These resources were not listed in eGRID data because they were not online in 2010. The APS 2014 IRP lists "APS-entitled MW" but does not include capacity factors for specific resources.

¹³ APS 2014 IRP. P. 288.

¹⁴ The eGRID data lists this generation resource as belonging to Imperial Irrigation District, not APS.

adjusted annual net generation (MWh) of all plants in order to develop an emission rate (MTCO₂e/MWh) for each generation scenario.

Costs

Costs of potential underreporting due to the differences between these emission rates and the ARB default emission rates were calculated under two allowance prices: \$11.34 per allowance (MTCO₂e) and \$15.60 per allowance. \$11.34 was the reserve price of the most recent cap-and-trade auction in May of 2014,¹⁵ while \$15.60 was the mean price of the first cap-and trade auction, which took place in November of 2012.¹⁶ These figures are used as an upper and lower bounds of cost estimates. The potential total costs of allowances above the default emission rate were calculated by determining the annual emissions (MTCO₂e) that would be associated with the annual net generation for the year under a given scenario under the default emission rate of 0.428, and then subtracting that value from the actual metric tons emitted in the generation scenario. The allowance prices were then multiplied by the difference in emissions (MTCO₂e).

Results

The results of the emissions assessment using adjusted 2010 eGRID data showed a range of emission rates for APS between 0.5076 MTCO₂e/MWh and 0.8247 MTCO₂e/MWh, as shown in Table 6.

Updated Assessment Generation Scenarios	2010 Emission Rate (MTCO ₂ e/MWh)	2014 Emission Rate (MTCO ₂ e/MWh)
Total APS portfolio	0.5332	0.5076
APS portfolio, excluding nuclear energy	0.8027	0.7333
APS portfolio, excluding nuclear and renewable energy	0.8087	0.8247

Table 6. Emission rates for the Updated Assessment: APS generation scenarios in 2010 and 2014.

Table 7 shows the results of the Initial Assessment for the 2009 portfolio and 2012 projections.

Initial Assessment Generation Scenarios	2009 Emission Rate (MTCO ₂ e/MWh)	2012 Emission Rate (MTCO ₂ e/MWh)
APS portfolio	0.5241	0.5086
APS portfolio, excluding nuclear generation	0.6957	0.6686
APS portfolio, excluding nuclear and renewable generation	0.6950	0.7196

Table 7. 2009 and 2012 APS emission rates from the Initial Assessment.

Power Control Area Results

¹⁵ <http://www.arb.ca.gov/cc/capandtrade/auction/may-2014/results.pdf>

¹⁶ http://www.arb.ca.gov/cc/capandtrade/auction/november_2012/updated_nov_results.pdf

The eGRID categorizes and defines generation by individual PCA as, “a portion of an integrated power grid for which a single dispatcher has operational control of all electric generators”. This breakdown of data includes many of the plants listed in the assessment and provides aggregated values for annual net generation (MWh) and annual CO₂ equivalent emissions (MTCO₂e); the two values from which an emission rate can be calculated. The PCA data fully attributes all generation and emissions of the various power plants to APS, without adjusting for partial ownership. Based solely on the eGRID data with no adjustments, the overall emission rate for the entire APS PCA in 2010 was 0.8445 MTCO₂e/MWh. The PCA emission rate in the Initial Assessment of 2009 data was 0.8448 MTCO₂e/MWh. This indicates that between 2009 and 2010, the emission rate for the entire APS PCA decreased by 0.0003 MTCO₂e/MWh.

Power Control Area	PCA annual net generation (MWh)	PCA annual CO ₂ equivalent emissions (MT)
Arizona Public Service Company	27,506,392.8	23,230,502.9
PCA Emission Rate	0.8445 MT/CO ₂ e	

Table 8. Unadjusted emission rate for the APS PCA.

Potential Costs of the ARB Default Rate for Unspecified Electricity Imports

Assuming an allowance price of \$11.34 (per allowance, or MTCO₂e), we calculate a range of potential avoided allowance costs between \$25 million and \$76 million per year, and at an allowance price of \$15.60, the range of avoided allowance costs for APS could be between \$34 and \$105 million per year.

Updated Assessment Generation Scenarios	2010 costs above default emission rate (\$11.34/MT)	2010 costs above default emission rate (\$15.60/MT)	2014 costs above default emission rate (\$11.34/MT)	2014 costs above default emission rate (\$15.60/MT)
Total APS	\$32 million	\$44 million	\$25 million	\$34 million
APS excluding nuclear	\$76 million	\$104 million	\$66 million	\$91 million
APS excluding nuclear and renewable	\$76 million	\$105 million	\$76 million	\$105 million

Table 9. Potential costs of underreported emissions above ARB default rate.

Discussion

This Updated Assessment produced similar results to the Initial Assessment in that the entire range of emission rates calculated for both 2010 and 2014 are above the ARB default emission rate for unspecified electricity imports of 0.428 MTCO₂e/MWh as shown in Table 10 and Figure 1 below. As described in Table 10, the relationship of these emission rates to the ARB default

emission rate for unspecified imports ranges from 19% above the ARB default emission rate for the 2014 total APS portfolio, to 93% above the ARB default emission rate for the 2014 APS generation portfolio excluding nuclear and renewable generation. The generation and emissions data from 2010 indicates that the emission rate of the total APS's generation portfolio in 2010 was 25% higher than the ARB default emission rate.

Updated Assessment Generation Scenarios	2010 Emission Rates (MTCO ₂ e/MWh)	Percent above ARB default rate	2014 Emission Rates (MTCO ₂ e/MWh)	Percent above ARB default rate
APS portfolio	0.5332	25%	0.5076	19%
APS portfolio, excluding nuclear generation	0.8027	88%	0.7333	71%
APS portfolio, excluding nuclear and renewable generation	0.8087	89%	0.8247	93%

Table 10. Comparison of emission rates to ARB default emission rate for unspecified imports.

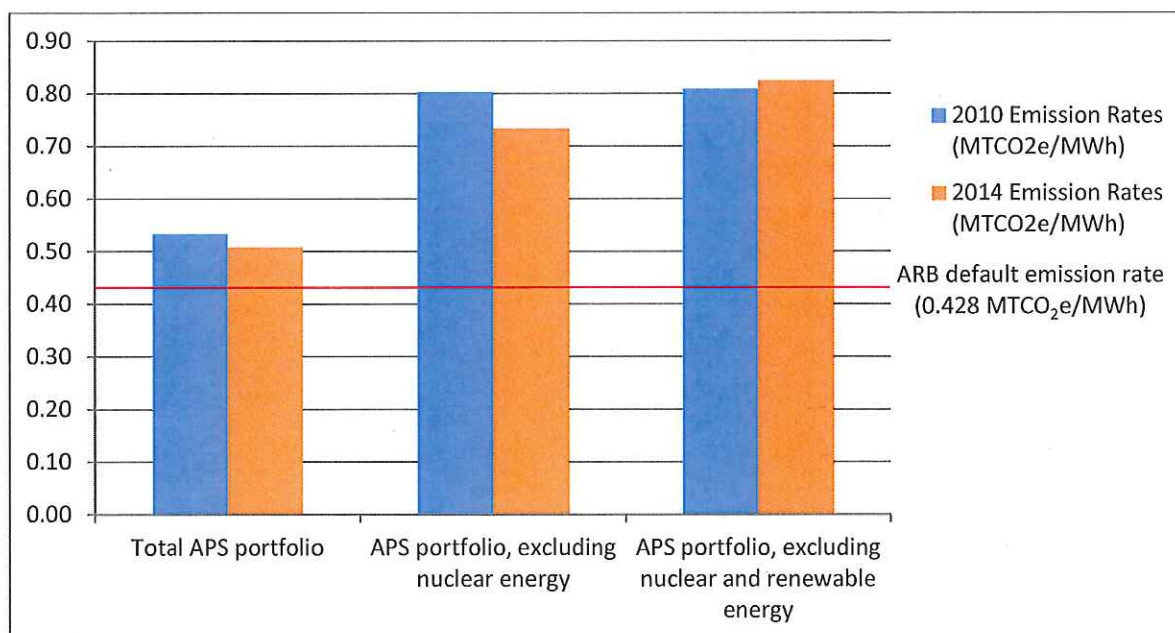


Figure 1. Comparison of 2010 and 2014 emission rates (in MTCO₂e/MWh) to ARB default emission rate for unspecified electricity imports.

2010 vs. 2014 Generation Scenarios

The results indicate that the 2014 GHG emission rate for APS's entire portfolio will likely decrease by 0.0256 MTCO₂e/MWh from its 2010 portfolio. This can be explained by the addition of approximately 770 MW of new renewable generation, including both owned generation and PPAs. This figure does not consider the additional 2,460 MW of PPAs for conventional resources that were discussed in the APS 2014 IRP, however, and is therefore

conservative. An assessment of the 2014 generation scenario without renewable or conventional PPAs yields an emission rate of 0.5450 MTCO₂e/MWh.

Updated Assessment Compared to Initial Assessment

The Initial Assessment and this Updated Assessment both use actual data from eGRID from 2009 and 2010. A comparison of 2009 emission rates to 2010 emission rates indicates that emissions increased slightly for the total portfolio between 2009 and 2010. It is not clear whether the difference is caused by the new data, changed assumptions, or an actual increase in emissions. As noted previously, a number of the plants included in the 2009 calculations were not included in the calculations to develop 2010 emission rates due to new information. However, both renewable and conventional generation was excluded based on up to date information regarding the plants, so it is unlikely to have had a profound effect on the results. The timeframe of 2009 to 2010 is too short to indicate an continuous trend, however the results do not indicate that APS is reducing emissions or that the APS portfolio is moving toward the ARB default emission rate.

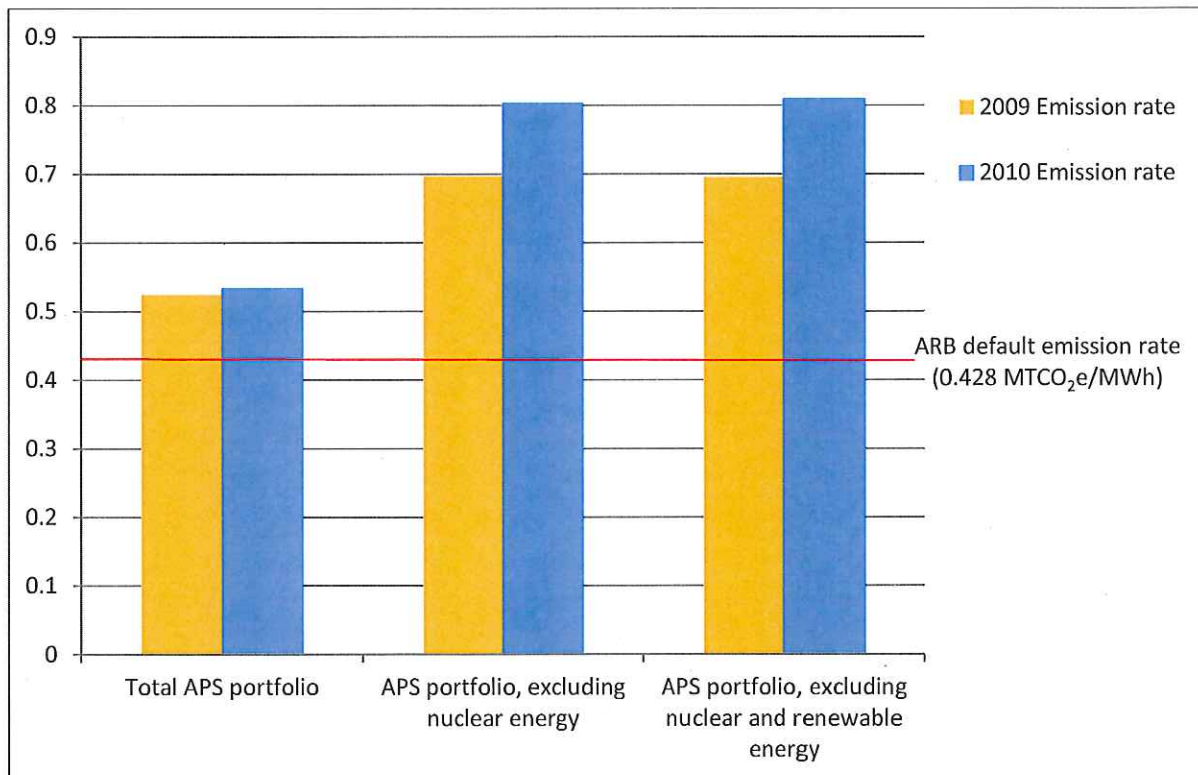


Figure 2. Comparison of 2009 and 2010 APS emission rates (in MTCO₂e/MWh).

Figure 3 illustrates the emission rate results of the Initial Assessment as well as this Updated Assessment. In all years, emission rates of the total APS portfolio are between 0.5000 and

0.5500 MTCO₂e/MWh.

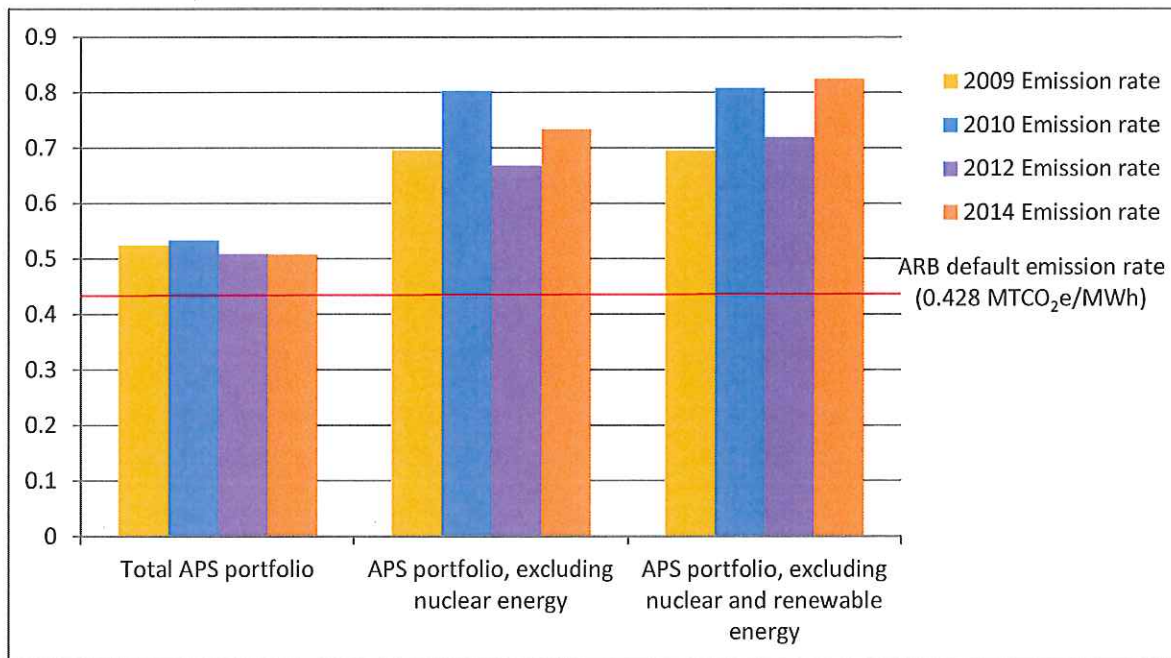


Figure 3. Emission rates (in MTCO₂e/MWh) of all APS portfolios in 2009 and 2010 and projections for 2012 and 2014.

Power Control Area Emission Rate

We observe a very minor difference in the PCA emission rate between 2009 and 2010 (a decrease in the emission rate by 0.0003 MTCO₂e/MWh), indicating that overall emissions in the Southwest region are well above the ARB default emission factor.

Avoided Allowance Costs

This Updated Assessment attempts to calculate the potential costs associated with unreported emissions above the ARB default emission rate. Avoided cost estimates for APS's generation scenarios are most likely in the tens of millions of dollars, if not higher, which can depress market prices for allowances. It can also encourage underreporting of higher-emitting resources by out of state electric power entities, reducing the effectiveness of the program and creating a competitive advantage for non-California participants.

Integrated Resource Planning

The APS 2014 IRP describes APS's plans to satisfy a need for 6,613 MW of additional resources and to continue operations of 6,412 MW of existing resources in 2029. The selected portfolio continues nuclear generation at current levels, and suggests a moderate increase in coal generation. In the 2029 resource portfolio, 24.5% will come from coal, 28.5% of from

natural gas, 13.6% from renewable energy and distributed generation, and 15.3% will result from energy efficiency and demand response.¹⁷ While some of the new generation will be free of GHG emissions, this planning regime is not likely to result in dramatic GHG emission reductions over time, and is therefore not likely to significantly result the total emission rate of the APS service territory or PCA over the next several years.

Conclusion

The range of emission rates offered in this analysis is intended to provide a sample of possible generation scenarios, with a number of adjustments, in an attempt to see how emission rates might change over time and with new procurement decisions. While a two-year timeframe is a small window, the comparison of 2009 emission rates with 2010 emission rates does not indicate a reduction of emission within the APS system. The comparison of 2010 emission rates with the 2014 projected emission rates suggests modest improvements, however APS appears focused on a business-as-usual trajectory for its planning horizon out to 2029, and significant emission reductions are therefore unlikely over time. While it is difficult to assess the amount and type of generation resources that California is importing, it is important to look at the range of emission rates from neighboring areas to better understand the mix of generation in a system at a given time. In looking at APS as a neighboring utility, it is important to consider the potential unintended consequences of setting a default emission rate below actual levels, such as market distortion and emissions leakage.

¹⁷ APS 2014 IRP. Executive Summary VII.

Appendix A: Data Tables and Calculations for APS Generation Scenarios

Plant name	Plant owner	Plant primary fuel generation category	Plant capacity factor - eGRID	Plant nameplate capacity (MW) - eGRID	Plant annual net generation (MWh) - eGRID	APS % of plant owned - eGRID	2010 APS-entitled nameplate capacity (MW)	2010 APS-entitled annual net generation (MWh)	Plant annual CO2e output emission rate (lb/MWh) - eGRID	APS CO2e emissions (MT)	GHG emission rate (MTCO2e/MWh)
Cholla	APS	Coal	0.7202	1,128.8	7,121,755	63%	714.76	4,509,362	2327	4,758,947	1.0553
Four Corners	APS	Coal	0.6994	2,269.6	13,904,804	39%	878.79	5,384,116	2063	5,085,998	0.9446
Navajo	SRP/AF	Coal	0.7785	2,409.3	16,429,593	74%	337.30	2,300,285	2179	2,273,091	0.9882
Douglas	APS	Oil	0.0019	21.4	359	100%	21.40	356	3579	578	1.6233
Ocotillo	APS	Gas	0.0191	334.0	55,777	100%	334.00	55,884	1575	39,933	0.7146
Redhawk	APS	Gas	0.3393	1,136.0	3,376,012	100%	1136.00	3,376,496	889	1,361,718	0.4033
Saguaro	APS	Gas	0.0023	435.5	8,741	100%	435.50	8,774	1271	5,057	0.5764
Sundance	APS	Gas	0.0273	450.0	107,797	100%	450.00	107,617	1310	63,943	0.5942
West Phoenix	APS	Gas	0.1627	1,206.8	1,719,691	100%	1206.80	1,719,994	789	615,884	0.3581
Yucca	APS	Gas	0.1249	385.5	421,666	71%	272.82	298,497	1294	175,251	0.5871
Palo Verde	APS	Nuclear	0.8461	4,209.3	31,199,935	29%	1224.91	9,078,805	0	0	0.0000
Prescott Airport	APS	Solar PV	0.3023	2.1	5,561	100%	2.10	5,561	0	0	0.0000
*Snowflake White Mtn	PPA	Biomass	0.6613	27.2	157,559	37%	10.00	57,922	78	2,037	0.0352
*Salton Sea	PPA	Geothermal	0.8280	184.8	1,336,000	5%	10.00	72,533	60	1,974	0.0272
2010 generation and emissions										14,384,411	0.5332
2010 APS emission factor											

Figure 1A. Total APS 2010 portfolio.

Plant name	Plant owner	Plant primary fuel generation category	Plant capacity factor - eGRID	Plant nameplate capacity (MW) - eGRID	Plant annual net generation (MWh) - eGRID	APS % of plant owned - eGRID	2010 APS-entitled nameplate capacity (MW)	2010 APS-entitled annual net generation (MWh)	Plant annual CO2e total output emission rate (lb/MWh) -	APS CO2e emissions (metric tons)	GHG emission rate (MTCO2e/MWh)
Cholla	APS	Coal	0.7202	1,128.8	7,121,755	63%	714.76	4,509,362	2327	4,758,947	1.0553
Four Corners	APS	Coal	0.6994	2,269.6	13,904,804	38%	857.91	5,256,188	2083	4,965,153	0.9446
Navajo	SRP/AF	Coal	0.7785	2,409.3	16,429,593	14%	337.30	2,300,285	2179	2,273,091	0.9882
Douglas	APS	Oil	0.0019	21.4	359	100%	21.40	356	3579	578	1.6233
Ocotillo	APS	Gas	0.0191	334.0	55,777	100%	334.00	55,884	1575	39,933	0.7146
Redhawk	APS	Gas	0.3393	1,136.0	3,376,012	100%	1,136.00	3,376,496	889	1,361,718	0.4033
Saguaro	APS	Gas	0.0023	435.5	8,741	100%	435.50	8,774	1271	5,057	0.5764
Sundance	APS	Gas	0.0273	450.0	107,797	100%	450.00	107,617	1310	63,943	0.5942
West Phoenix	APS	Gas	0.1627	1,206.8	1,719,691	100%	1,206.80	1,719,994	789	615,884	0.3581
Yucca	APS	Gas	0.1249	385.5	421,666	71%	272.82	298,497	1294	175,251	0.5871
Prescott Airport	APS	Solar PV	0.3023	2.1	5,561	100%	2.10	5,561	0	0	0.0000
*Snowflake White Mountain	PPA	Biomass	0.6613	27.2	157,559	37%	10.00	57,922	78	2,037	0.0352
*Salton Sea	PPA	Geothermal	0.8280	184.8	1,336,000	5%	10.00	72,533	60	1,974	0.0272
2010 generation and emissions, excluding nuclear energy										14,263,566	0.8027
2010 APS emission rate, excluding nuclear energy										17,769,470	0.8027

Figure 2A. APS 2010 portfolio, excluding nuclear energy.

Plant name	Plant owner	Plant primary fuel generation category	Plant capacity factor - eGRID	Plant nameplate capacity (MW) - eGRID	Plant annual net generation (MWh) - eGRID	APS % of plant owned - eGRID	2010 APS-entitled nameplate capacity (MW)	2010 APS-entitled annual net generation (MWh)	Plant annual CO2e total output emission rate (lb/MWh) - eGRID	APS CO2e emissions (metric tons)	GHG emission rate (MTCO2e/MWh)
Cholla	APS	Coal	0.7202	1,128.8	7,121,755	63%	714.76	4,509,362	2327	4,758,947	1.0553
Four Corners	APS	Coal	0.6994	2,269.6	13,904,804	38%	857.91	5,256,188	2083	4,965,153	0.9446
Navajo	SRP/AF	Coal	0.7785	2,409.3	16,429,593	14%	337.30	2,300,285	2179	2,273,091	0.9882
Douglas	APS	Oil	0.0019	21.4	359	100%	21.40	356	3579	578	1.6233
Ocotillo	APS	Gas	0.0191	334.0	55,777	100%	334.00	55,884	1575	39,933	0.7146
Redhawk	APS	Gas	0.3393	1,136.0	3,376,012	100%	1,136.00	3,376,496	889	1,361,718	0.4033
Saguaro	APS	Gas	0.0023	435.5	8,741	100%	435.50	8,774	1271	5,057	0.5764
Sundance	APS	Gas	0.0273	450.0	107,797	100%	450.00	107,617	1310	63,943	0.5942
West Phoenix	APS	Gas	0.1627	1,206.8	1,719,691	100%	1,206.80	1,719,994	789	615,884	0.3581
Yucca	APS	Gas	0.1249	385.5	421,666	71%	272.82	298,497	1294	175,251	0.5871
2010 generation and emissions, excluding nuclear and renewable energy										14,259,554	
2010 APS emission rate excluding nuclear and renewable energy										0.8087	

Figure 3A. APS 2010 portfolio, excluding nuclear and renewable energy.

Plant name	Plant owner	Plant primary fuel generation category	Plant capacity factor - eGRID	2014 APS-entitled nameplate capacity (MW) - 2014 IRP	2014 APS-entitled annual net generation (MWh)	Plant 2010 CO2e total output emission rate (lb/MWh) - eGRID if available	APS-owned 2014 CO2e emissions (lbs)	APS-owned 2010 CO2e emissions (metric tons)	2014 GHG emission rate (MTCO2e/MWh)
Cholla	APS	Coal	0.7202	647	4,081,892	2,327	9,497,109,808	4,307,817	1.0553
Four Corners	APS	Coal	0.6994	970	5,942,942	2,083	12,376,489,836	5,613,881	0.9446
Navajo	SRP/APS	Coal	0.7785	315	2,148,193	2,179	4,679,967,124	2,122,797	0.9882
Douglas	APS	Oil	0.0019	15	250	3,579	893,475	405	1.6233
Ocotillo	APS	Gas	0.0191	320	53,541	1,575	84,347,465	38,259	0.7146
Red Hawk	APS	Gas	0.3393	1,000	2,972,268	889	2,642,670,526	1,198,695	0.4033
Saguaro	APS	Gas	0.0023	176	3,546	1,271	4,505,840	2,044	0.5764
Sundance	APS	Gas	0.0273	410	98,051	1,310	128,438,596	58,259	0.5942
West Phoenix	APS	Gas	0.1627	998	1,422,401	789	1,122,866,784	509,324	0.3581
Yucca	APS	Gas	0.1249	233	254,931	1,294	329,971,840	149,673	0.5871
Palo Verde	APS	Nuclear	0.8461	1,146	8,493,964	0	0	0	0.0000
Paloma Solar	APS	Solar PV	0.2100	17	31,273	0	0	0	0.0000
Cotton Center	APS	Solar PV	0.2100	17	31,273	0	0	0	0.0000
Hyder Solar	APS	Solar PV	0.2100	16	29,434	0	0	0	0.0000
Hyder II Solar	APS	Solar PV	0.2100	14	25,754	0	0	0	0.0000
Chino Valley	APS	Solar PV	0.2100	19	34,952	0	0	0	0.0000
Foothills Plant	APS	Solar PV	0.2100	35	64,386	0	0	0	0.0000
*Ajo Project	PPA	Solar PV	0.2100	5	9,198	0	0	0	0.0000
*SunEdison Prescott Project	PPA	Solar PV	0.2100	10	18,396	0	0	0	0.0000
*Saddle Mountain	PPA	Solar PV	0.2100	15	27,594	0	0	0	0.0000
*PSEG Badger-Desert Sky	PPA	Solar PV	0.2100	15	27,594	0	0	0	0.0000
*RE Gillespie	PPA	Solar PV	0.2100	15	27,594	0	0	0	0.0000
*Solana	PPA	CSP + TES	0.4100	270	969,732	0	0	0	0.0000
*Aragonne Mesa Wind Project	PPA	Wind	0.2300	90	181,332	0	0	0	0.0000
*High Lonesome Wind Project	PPA	Wind	0.2300	100	201,480	0	0	0	0.0000
*Perrin Ranch Wind Project	PPA	Wind	0.2300	99	199,465	0	0	0	0.0000
*Salton Sea Geothermal	PPA	Geothermal	0.9600	10	84,096	60	5,045,760	2,289	0.0272
*Glendale Biogas Project	PPA	Biogas	0.8800	3	23,126	0	0	0	0.0000
*NW Regional Biogas Project	PPA	Biogas	0.8800	3	23,126	0	0	0	0.0000
*Snowflake White Mountain	PPA	Biomass	0.8500	14	104,244	0	0	0	0.0000
2014 generation and emissions					27,586,029			14,003,443	0.5076

Figure 4A. 2014 APS portfolio, including renewable PPAs and not including conventional PPAs.

Plant name	Plant owner	Plant primary fuel generation category	Plant capacity factor - eGRID	2014 APS-entitled nameplate capacity (MW) - 2014 IRP	2014 APS-entitled annual net generation (MWh)	Plant 2010 CO2e total output emission rate (lb/MWh) - eGRID if	APS-owned 2014 CO2e emissions (lbs)	APS-owned 2010 CO2e emissions (metric tons)	2014 GHG emission rate (MTCO2e/MWh)
Cholla	APS	Coal	0.7202	647	4,081,892	2,327	9,497,109,808	4,307,817	1.0553
Four Corners	APS	Coal	0.6994	970	5,942,942	2,083	12,376,489,836	5,613,881	0.9446
Navajo	SRP/APS	Coal	0.7785	315	2,148,193	2,179	4,679,967,124	2,122,797	0.9882
Douglas	APS	Oil	0.0019	15	250	3,579	893,475	405	1.6233
Ocotillo	APS	Gas	0.0191	320	53,541	1,575	84,947,465	38,259	0.7146
Red Hawk	APS	Gas	0.3393	1000	2,972,268	889	2,642,670,526	1,198,695	0.4033
Saguaro	APS	Gas	0.0023	176	3,546	1,271	4,505,840	2,044	0.5764
Sundance	APS	Gas	0.0273	410	98,051	1,310	128,438,596	58,259	0.5942
West Phoenix	APS	Gas	0.1627	998	1,422,401	789	1,122,866,784	509,324	0.3581
Yucca	APS	Gas	0.1249	233	254,931	1,294	329,971,840	149,673	0.5871
Paloma Solar	APS	Solar PV	0.2100	17	31,273	0	0	0	0.0000
Cotton Center	APS	Solar PV	0.2100	17	31,273	0	0	0	0.0000
Hyder Solar	APS	Solar PV	0.2100	16	29,434	0	0	0	0.0000
Hyder II Solar	APS	Solar PV	0.2100	14	25,754	0	0	0	0.0000
Chino Valley	APS	Solar PV	0.2100	19	34,952	0	0	0	0.0000
Foothills Plant	APS	Solar PV	0.2100	35	64,386	0	0	0	0.0000
*Ajo Project	PPA	Solar PV	0.2100	5	9,198	0	0	0	0.0000
*SunEdison Prescott Project	PPA	Solar PV	0.2100	10	18,396	0	0	0	0.0000
*Saddle Mountain	PPA	Solar PV	0.2100	15	27,594	0	0	0	0.0000
*PSEG Badger-Desert Sky	PPA	Solar PV	0.2100	15	27,594	0	0	0	0.0000
*RE Gillespie	PPA	Solar PV	0.2100	15	27,594	0	0	0	0.0000
*Solana	PPA	CSP + TES	0.4100	270	969,732	0	0	0	0.0000
*Aragonne Mesa Wind Project	PPA	Wind	0.2300	90	181,332	0	0	0	0.0000
*High Lonesome Wind Project	PPA	Wind	0.2300	100	201,480	0	0	0	0.0000
*Perrin Ranch Wind Project	PPA	Wind	0.2300	99	199,465	0	0	0	0.0000
*Salton Sea Geothermal	PPA	Geothermal	0.9600	10	84,096	0	0	0	0.0000
*Glendale Biogas Project	PPA	Biogas	0.8800	3	23,126	0	0	0	0.0000
*NW Regional Biogas Project	PPA	Biogas	0.8800	3	23,126	0	0	0	0.0000
*Snowflake Biomass Project	PPA	Biomass	0.8500	14	104,244	0	0	0	0.0000
2014 generation and emissions, excluding nuclear energy						19,092,065		14,001,154	0.7333
2014 APS emission rate excluding nuclear energy									0.7333

Figure 5A. 2014 APS portfolio, excluding nuclear energy.

Plant name	Plant owner	Plant primary fuel generation category	Plant capacity factor - eGRID	2014 APS-entitled nameplate capacity (MW) - 2014 IRP	2014 APS-entitled annual net generation (MWh)	Plant 2010 CO2e total output emission rate (lb/MWh) - eGRID if available	APS-owned 2014 CO2e emissions (lbs)	APS-owned 2010 CO2e emissions (metric tons)	2014 GHG emission rate (MTCO2e/MWh)	
Cholla	APS	Coal	0.7202	647	4,081,892	2,327	9,497,109,808	4,307,817	1.0553	
Four Corners	APS	Coal	0.6994	970	5,942,942	2,083	12,376,489,836	5,613,881	0.9446	
Navajo	SRP/APS	Coal	0.7785	315	2,148,193	2,179	4,679,967,124	2,122,797	0.9882	
Douglas	APS	Oil	0.0019	15	250	3,579	893,475	405	1.6233	
Ocotillo	APS	Gas	0.0191	320	53,541	1,575	84,347,465	38,259	0.7146	
Red Hawk	APS	Gas	0.3393	1000	2,972,268	889	2,642,670,526	1,198,695	0.4033	
Saguaro	APS	Gas	0.0023	176	3,546	1,271	4,505,840	2,044	0.5764	
Sundance	APS	Gas	0.0273	410	98,051	1,310	128,438,596	58,259	0.5942	
West Phoenix	APS	Gas	0.1627	998	1,422,401	789	1,122,866,784	509,324	0.3581	
Yucca	APS	Gas	0.1249	233	254,931	1,294	329,971,840	149,673	0.5871	
2014 generation and emissions, excluding nuclear and renewables								14,001,154	0.8247	
2014 APS emission rate excluding nuclear and renewable energy										0.8247

Figure 6A. APS 2014 portfolio, excluding nuclear and renewable energy.

Plant name	Plant owner	Plant primary fuel generation category	Plant capacity factor - eGRID	2014 APS-entitled nameplate capacity (MW) - 2014 IRP	2014 APS-entitled annual net generation (MWh)	Plant 2010 CO2e total output emission rate (lb/MWh) - eGRID if available	APS-owned 2014 CO2e emissions (lbs)	APS-owned 2010 CO2e emissions (metric tons)	2014 GHG emission rate (MTCO2e/MWh)
Cholla	APS	Coal	0.7202	647	4,081,892	2,327	9,497,109,808	4,307,817	1.0553
Four Corners	APS	Coal	0.6994	970	5,942,942	2,083	12,376,489,836	5,613,881	0.9446
Navajo	SRP/APS	Coal	0.7785	315	2,148,193	2,179	4,679,967,124	2,122,797	0.9882
Douglas	APS	Oil	0.0019	15	250	3,579	893,475	405	1.6233
Ocotillo	APS	Gas	0.0191	320	53,541	1,575	84,347,465	38,259	0.7146
Red Hawk	APS	Gas	0.3393	1,000	2,972,268	889	2,642,670,526	1,198,695	0.4033
Saguaro	APS	Gas	0.0023	176	3,546	1,271	4,505,840	2,044	0.5764
Sundance	APS	Gas	0.0273	410	98,051	1,310	128,438,596	58,259	0.5942
West Phoenix	APS	Gas	0.1627	998	1,422,401	789	1,122,866,784	509,324	0.3581
Yucca	APS	Gas	0.1249	233	254,931	1,294	329,971,840	149,673	0.5871
Palo Verde	APS	Nuclear	0.8461	1,146	8,493,964	0	0	0	0.0000
Paloma Solar	APS	Solar PV	0.2100	17	31,273	0	0	0	0.0000
Cotton Center	APS	Solar PV	0.2100	17	31,273	0	0	0	0.0000
Hyder Solar	APS	Solar PV	0.2100	16	29,434	0	0	0	0.0000
Hyder II Solar	APS	Solar PV	0.2100	14	25,754	0	0	0	0.0000
Chino Valley	APS	Solar PV	0.2100	19	34,952	0	0	0	0.0000
Foothills Plant	APS	Solar PV	0.2100	35	64,386	0	0	0	0.0000
2014 generation and emissions, excluding PPAs						25,689,051		14,001,154	0.5450
2014 APS emission rate, excluding PPAs									0.5450

Figure 7A. 2014 APS portfolio, excluding renewable and conventional PPAs.