Carbon Metric: An Analytical Framework for Comparing the Cost-Effectiveness of AB 32 Greenhouse Gas Abatement Activities

Version 2.0

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1 Executive Summary

The next few years will be critical for determining whether, and in what fashion, California meets its greenhouse gas (GHG) reduction goals under the California Global Warning Solutions Act of 2006 (AB 32). By January 1, 2014 the California Air Resources Board (ARB) will update the comprehensive strategy for how these goals will be achieved, known as the AB 32 Scoping Plan. In support of this effort, PG&E created this study with the following key objectives:

- ***Encourage stakeholder engagement around a standardized analytical framework to evaluate cost-effectiveness across greenhouse gas abatement activities known as the "Carbon Metric".*** The Carbon Metric is the average cost of obtaining one metric ton of GHG emissions reductions ($ per metric ton) through a given abatement activity. We demonstrate that this value can be derived for all major AB 32 measures and propose a framework for comparing these Carbon Metric values to cap-and-trade carbon prices to assess cost-effectiveness.
- ***Provide a "status-check" on the 2020 abatement estimates of major AB 32 measures as currently constructed, including:*** Energy Efficiency (EE), the Renewable Portfolio Standard (RPS), the Low Carbon Fuel Standard (LCFS), Combined Heat and Power (CHP) and Offset Credits.
- ***Provide a tool that can be used to prioritize abatement activities in the post-2020 timeframe.*** ARB and other California thought-leaders are beginning to consider the development of future greenhouse gas policies. The Carbon Metric framework provides a key tool to assist in evaluation and prioritization of these policies.
- ***Promote a constructive dialogue about sensible and affordable clean energy policy.*** PG&E supports AB 32 and believes it can be achieved cost-effectively. We favor the use of rigorous and transparent analytics that are inclusive of all reasonable stakeholder viewpoints.

The Need for an AB 32 Cost-Effectiveness Metric

AB 32 makes specific reference to ensuring the cost-effectiveness of greenhouse gas reduction activities and defines cost-effectiveness as the cost per unit of reduced emissions of greenhouse gases. However, the bill does not precisely identify which costs should be considered, or define a 'bright line' point of reference that can be used to draw a distinction between actions that are cost-effective and those that are not. The Carbon Metric framework proposed in this paper addresses these issues by identifying which costs and benefits should be included in the initial analysis[1] and identifying solutions to many of the challenging technical

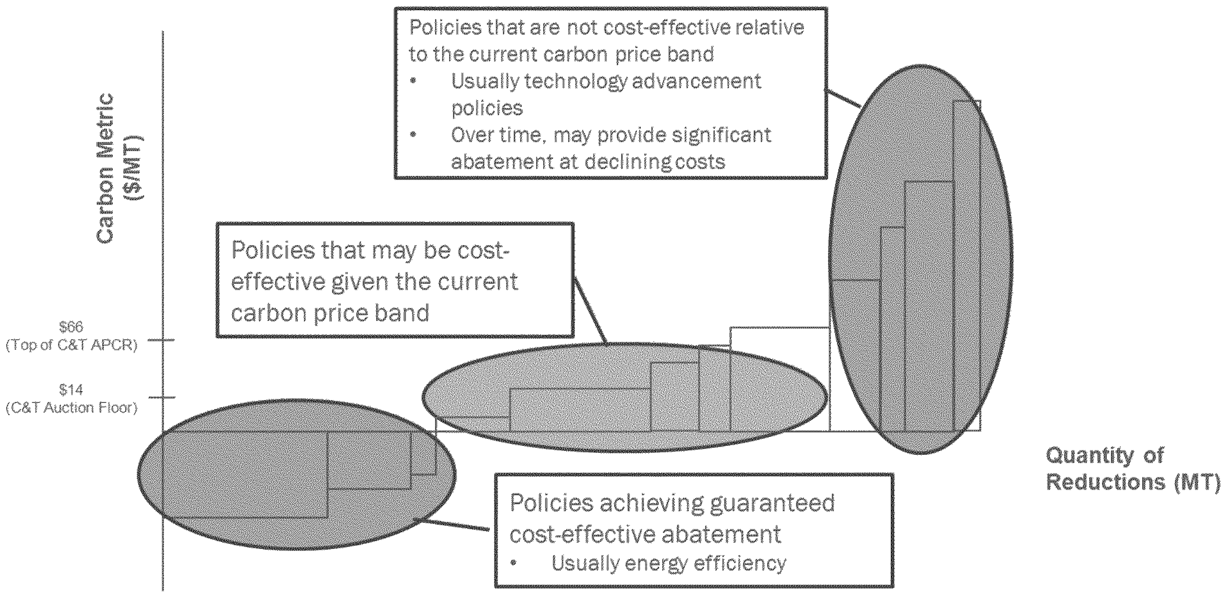
[1] The Carbon Metric uses a "total resource cost perspective" (TRC) as an initial cost screen. We recommend a societal cost screen as a secondary evaluation for measures with high TRC values. This

aspects of creating a proper apples -to-apples comparison between disparate GHG abatement activities.

The Carbon Metric Provides Two-Way Visibility between Carbon Prices and the Cost-Effectiveness of AB 32 Program Measures

Under perfect market conditions , carbon pricing is the key element of a least -cost policy framework to reduce GHGs. The ARB's cap-and-trade program provides a transparent band of expected carbon prices between now and 2020. This price band is implemented through the "Auction Floor Price" (which will reach approximately $14/metric ton in 2020) and a soft price ceiling known as the "Allowance Price Containment Reserve" (which will reach approximately $66/metric ton in 2020).[2] This price band can be used to define three cost-effectiveness categories as shown in Figure ES-1.[3]

Figure ES-1. Three Carbon Metric Categories of Greenhouse Gas Abatement Activities



work is built upon the cost tests used at the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to evaluate energy efficiency cost-effectiveness.

[2] These values are reported in real 2010 dollars for consistency with other values in this report.

[3] Note that the groupings shown in Figure ES-1 correspond to the color coding of Tables ES-1 through ES-3.

Demonstration of Concept – Applying the Carbon Metric to Current Scoping Plan Program Measures and Offset Credit Protocols

To demonstrate the value of the Carbon Metric concept, we apply the framework to the major AB 32 measures identified in the 2008 Scoping Plan and to potential offset credit project types under the cap-and-trade program. As part of the Carbon Metric framework, we recommend constructing at least two plausible scenarios, one representing an optimistic outcome (i.e., lower costs and/or higher GHG abatement) and one representing a pessimistic outcome (i.e., higher costs and/or lower GHG abatement). Table ES-1 summarizes the average unit abatement cost and the 2020 GHG abatement estimate by measure, and Table ES-2 summarizes estimates of the average unit abatement costs and the cumulative 2013-2020 GHG abatement provided by offset credits.

Table ES-1. Summary of Abatement and Unit Abatement Costs – Program Measures

Program Measure	Plausible Low Cost		Plausible High Cost	
	2020 Abatement (Million Metric Tons)	*Average Abatement Cost ($/Metric Ton)*	*2020 Abatement (Million Metric Tons)*	*Average Abatement Cost ($/Metric Ton)*
Low Carbon Fuel Standard*	16.3	$94	14.9	$182
Renewables	12.9	$149	12.9	$201
Energy Efficiency (Electric)	12.5	($114)	9.4	($101)
Energy Efficiency (Natural Gas)	1.6	($108)	1.6	($79)
Combined Heat and Power**	0.6	$7	0.05	$112

* LCFS values reported on a well-to-wheel basis

** Analysis was limited to topping-cycle CHP and did not consider renewable or bottoming-cycle CHP

All $ values in constant 2010 dollars

Color Code	Abatement	Abatement Costs
	Achieving program targets	Low Cost (<$14/MT)
	Slightly below program targets	Moderate Cost($14<x<$66)
	Significantly below program targets	High Cost (>$66/MT)

Table ES-2: Summary of Abatement and Unit Abatement Costs – Offsets

Protocol Type	Plausible Low Cost		Plausible High Cost	
	2013-2020 Cumulative Abatement Potential (Million Metric Tons)	*Average Abatement Cost ($/Metric Ton)*	*2013-2020 Cumulative Abatement Potential (Million Metric Tons)*	*Average Abatement Cost ($/Metric Ton)*
Approved Protocols*	77	$17	68	$44
Under Consideration Protocols**	85	$21	75	$48
Speculative Protocols***	239	$15	202	$39

Estimates include offsets created between 2005-2012 that could be eligible for compliance.
* Forestry, Livestock, ODS, and Urban Forestry
** Coal Mine Methane and Rice Cultivation
*** Eight protocols that have been developed and could be considered for inclusion as compliance offset protocols by the ARB in the future.

+ Abatement potential compared to the total amount of allowable offsets permitted by the ARB cap-and-trade rule (218 MMT, cumulative from 2013-2020).

All $ values in constant 2010 dollars

Color Code	Abatement+	Abatement Costs
	Achieving program targets	Low Cost (<$14/MT)
	Slightly below program targets	Moderate Cost($14<x<$66)
	Significantly below program targets	High Cost (>$66/MT)

Abatement Cost Observations

We observe a wide range in the abatement cost of the major Scoping Plan measures; from energy efficiency measures that save Californians on the order of one hundred dollars per ton reduced, to RPS and LCFS activities that cost as much as two hundred dollars per metric ton. In general, the ordinal rankings of the measures' cost-effectiveness remain consistent between the high and the low cost scenarios but the magnitude of each measure's $/metric ton value changes significantly between scenarios.

Taking a narrow view, a least-cost response would entail maximizing low cost options, such as energy efficiency, prior to expanding implementation of expensive measures such as RPS or the LCFS. A broader view of cost-effectiveness looks beyond prioritizing only on what is least-cost between now and 2020, and recognizes that some amount of high cost activities today may be needed to drive down costs in the future.

Employing this broader view, the justification for the existing GHG program measures can conceptually be divided into three categories: (1) guaranteed cost-effective policies designed to remove investment barriers (e.g., energy efficiency); (2) moderate cost actions that are within the range of current carbon prices (e.g., offset credits); and (3) high cost technology advancement policies that are not cost-effective relative to current carbon prices but may be needed to facilitate innovation and reduce the costs of long-term carbon reduction (e.g., RPS and LCFS).

2020 Abatement Observations

Major drivers of abatement include RPS, LCFS, and Electric EE. CHP and Gas EE offer more modest contributions. If additional offset protocols are approved and the market develops, offset credits can provide significant abatement. The magnitude of 2020 abatement estimates from EE, RPS and the LCFS are generally consistent with the most current estimates published by ARB. Our analysis predicts 2020 abatement from CHP to be significantly below the most recent ARB estimate and identifies some possible challenges in achieving the LCFS program abatement targets under the more pessimistic scenario.

Proposed Use of the Carbon Metric Framework

The Carbon Metric concept could be employed to guide both pre-2020 AB 32 implementation and any post-2020 California GHG policy. Adoption of the decision-making framework shown in Table ES-3 will ensure that GHG reductions are implemented cost-effectively.

The carbon price band administratively chosen by ARB provides a good indication of California's "willingness to pay" for GHG reductions. We believe that measures that fall above this expected carbon price band deserve the most attention. In general, these high-cost investments should only be undertaken if there is a recognized potential for significant future abatement coupled with expected cost reductions over time. Any policy of this type should be constructed as broad as possible to achieve GHG reductions (e.g., support for all low carbon fuels through LCFS is preferable to support for one specific low carbon fuel) and should have to demonstrate, through additional analysis, that net social benefits outweigh costs to California. Further, we believe that decision makers should explore funding the "above-market" portion of high-cost electric and gas program measures using sources other than utility customer rates.

Table ES-3: Use of the Carbon Metric and Cap-and-Trade Carbon Price Band to Prioritize Implementation of AB 32 Actions

If The Carbon Metric is:	Cost-effectiveness Category	Proposed Action
1. Less than the 2020 Auction Price Floor (~$14/ metric ton CO2e*)	Always cost-effective	➢ Prioritize implementation ➢ Unlock abatement potential otherwise untapped by the carbon price signal ➢ Identify and address any barriers to adoption
2. Between the 2020 Auction Price Floor and the top price of the 2020 Allowance Price Containment Reserve (APCR)	May be cost-effective today, depending on carbon price	➢ Should be prioritized after measures in Group 1 ➢ Explore likelihood of cap-and-trade price signal driving reductions in this category
3. Above the top of the 2020 APCR (~$66/ metric ton CO_2e*)	Unlikely to be cost-effective under expected near-term carbon prices	➢ Ensure actions are focused on achieving market transformation and reducing costs for long-term carbon reductions ➢ Evaluate if societal benefits outweigh societal costs ➢ Devote extra efforts to cost reduction ➢ Employ funding sources other than utility customer rates

* Carbon prices in this table are values in 2020 presented in constant 2010 dollars.

In summary, the Carbon Metric framework, coupled with carbon prices from cap-and-trade, provides a flexible method of assessing the cost-effectiveness and likely abatement from planned actions to reduce GHGs. This analytical framework can be used to prioritize efforts in a variety of AB 32 proceedings. Possible specific areas of application include: new and revised AB 32 Scoping Plan program measures, prioritization of expenditure of cap-and-trade auction revenues, deployment of Proposition 39 funds and any post-2020 GHG reduction legislation or regulation. A collaborative approach among all interested participants to further refine and effectively deploy this framework is recommended.

2 Introduction and Background

The Global Warming Solutions Act of 2006 (AB 32), a California state law, mandates the reduction of statewide greenhouse gas (GHG) emissions to 1990 levels by 2020. AB 32 makes specific reference to cost -effectiveness of GHG reductions activities and defines cost-effectiveness as the cost per unit of reduced emissions of GHGs.[4] However, the bill does not precisely identify which costs should be considered, or define a "bright line" point of reference that can be used to draw a distinction between actions that are "cost -effective" and those that are not.

PG&E created this Carbon Metric framework in an attempt to present a robust and transparent approach to addressin g the cost -effectiveness requirement of AB 32. PG&E has long been a leader in reducing GHG emissions and we believe this framework can c ontribute constructively to informed policy discussions about cost-effectiveness of GHG abatement.

This paper is organized into four sections:

- ***Introduction and Background on Cost-Effectiveness Analysis.*** This section provides the motivation for the Carbon Metric framework, including some relevant history of various economic analyses related to AB 32. This section also presents background on the usefulness of cost -effectiveness/cost-benefit analysis in other venues and describes how the total resource cost perspective and societal cost perspective are used to examine cost-effectiveness by the CPUC.
- ***Proposed Analy tical Framework.*** This section describes the 'nuts and bolts' of the Carbon Metric framework, including a description of how the total resource c ost perspective was adapted for this work and the conceptual motivation behind scenario development.
- ***Demonstration of Concept – Applying the Carbon Metric to Current Scoping Plan Program Measures .*** This section demonstrates the use fulness of th e framework by evaluating the relative cost -effectiveness of the major programs developed to meet the AB 32 goal statewide. This work provides an up-to-date assessment[5], based on the best publicly available information, of the likely level of emission reductions and range of abatement costs for five major components of the AB 32 program. The focus of this analysis is on the Scoping Plan Measures as currently designed. We do not attempt to

[4] "Cost-effective" or "cost-effectiveness" means the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential." §38505(d) of the Health and Safety Code

[5] The 2008 Scoping Plan (ARB 2008a) provides emission reduction estimates from each measure. The measure emissions reduction estimates were updated by ARB in a 2011 analysis conducted to supplement the original 2008 Scoping Plan (ARB 2011). We view this Carbon Metric analysis of existing measures as a useful starting point for a similar update.

anticipate updates or changes to the measures, nor do we attempt to consider the total supply curve of potential abatement from each type of action included in this analysis.

- ***Potential Future Applications of the Carbon Metric.*** We show how coupling the Carbon Metric for a given abatement action with the band of carbon prices expected from ARB's cap-and-trade program can be used to prioritize GHG abatement activities. We suggest possible venues for future use of this framework.

2.1 Background on Cost-Effectiveness Analysis

Cost-effectiveness and cost-benefit analysis has been used to inform state and federal environmental and energy policies for decades.[6] This section presents a short background on the approaches used by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC) for in the utility regulatory context, as well as describing the approaches taken at the US Environment Protection Agency (EPA) and ARB.

In general, the goal of cost-effectiveness analysis is to compare the costs of the policy with the benefits of the policy; if the benefits are greater than the costs, then the policy is determined to be "cost-effective". In both California utility cost-effectiveness evaluation and federal air quality regulation cost-effectiveness evaluation a distinction is drawn between the *total resource* and *societal* perspectives. Using these two perspectives, policies and programs are deemed to be cost-effective if they are economically attractive to all consumers (total resource perspective) or society as a whole (societal perspective). These terms have specific connotations in the utility regulatory world. We describe these terms in more detail below.

2.1.1 Cost-Effectiveness Evaluation in the Utility Regulatory Context

Cost-effectiveness evaluation for distributed energy resources (DERs) has a long history in utility regulation in the United States, dating back to the 1970s when energy efficiency programs were first developed. In California, cost-effectiveness evaluation for DERs is described in the California Standard Practice Manual for the Economic Analysis of Demand-Side Programs and Projects issued by the CPUC and CEC.[7] There are five main cost-effectiveness tests in this

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[6] A strict distinction is sometimes drawn between cost-effectiveness and cost-benefit analysis. For example, Cellini (2010) states that: "*cost-effectiveness* analysis seeks to identify and place dollars on the costs of a program. It then relates these costs to specific measures of program effectiveness"… "Like cost-effectiveness analysis, *cost-benefit analysis* also identifies and places dollar values on the costs of programs, but it goes further, weighing those costs against the dollar value of program benefits." For our purposes such a sharp distinction is not usually necessary and we default to the term "cost-effectiveness" analysis.

[7] Commonly referred to as the Standard Practice Manual (CPUC 2001). The National Action Plan for Energy Efficiency (E3 2008) also provides an excellent description of cost-effectiveness evaluation as it is applied towards energy efficiency program planning.

manual.[8] The Total Resource Cost (TRC) is the primary test used to evaluate the overall cost-effectiveness of DERs in California (and many other jurisdictions). It measures the net benefits to the region as a whole, irrespective of who bears the costs and receives the benefits. The incremental costs of purchasing and installing the DER system above the cost of standard equipment that would otherwise be installed, and the overhead costs of running the DER program are considered. The avoided costs are the benefits. Bill savings and in-state incentive payments are not included, as they are transfer payments between jurisdictional entities ('benefits' to customers and 'costs' to the utility that cancel each other on a regional level).

The Societal Cost Test (SCT), which is a variant of the TRC, has long been included in the Standard Practice Manual, but in has never been applied in a CPUC proceeding. The primary differences are consideration of additional non-monetized costs and benefits and use of a lower discount rate.[9]

The final output of cost-effectiveness evaluation is typically in the form of present value of the net benefits (i.e., present value of the benefits minus present value of the costs) or the ratio of benefits to costs. In the case of the former, a positive value renders a cost test result that 'passes', while in the case of the ratio, a value greater than or equal to one is equivalent to a 'passing' result. Each state's utility commission will have its own methods for how cost test results inform program design; however, in general, passing cost test results are required to justify the program investment.[10]

2.1.2 Cost-Effectiveness Evaluation of Federal Air Quality Regulations

The EPA prepares economic analysis to support the development of all air pollution regulations. These are known as 'Regulatory Impact Analyses (RIAs)'. The RIAs necessarily include the non-monetized benefits from proposed regulations. That is, the EPA adopts a societal cost test approach. This includes, for example, the economic value of reduced mortality rates due to lower emissions of fine particulate matter. In the case of GHGs, the EPA adopts a "social cost of carbon" (SCC) to estimate the societal benefits of reducing GHGs.[11]

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[8] See appendix for more details on these five tests.

[9] See *CPUC 2013*.

[10] There are exceptions to this rule, such as market transformation programs, which do not require passing cost test results.

[11] The work that the EPA and other federal agencies have done to quantify the social benefits of greenhouse gas reduction is substantial but many areas of uncertainty remain. See: http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

2.1.3 Brief History of Economic Analysis of AB 32

The original ARB economic analysis of the AB 32 scoping plan (ARB 2008b) received criticism from academic experts (see Stavins 2008, for example). A key criticism was that the analysis did not include a comparison of the costs of ARB's chosen portfolio of policies with alternative portfolios and, thus, the analysis did not provide the means to assess if the ARB's Scoping Plan truly represented a cost-effective means of reducing California's contribution to GHG emissions as required by AB 32.

In response to this and other criticisms, the ARB formed an expert advisory committee, the "Economic and Allocation Advisory Committee" (EAAC), which worked closely with the ARB to improve the economic analysis and reporting of the results. A review of ARB's updated economic analysis (ARB 2010d) by the EAAC was included as an appendix to the updated analysis (EAAC 2010).[12] The EAAC highlighted strengths and limitations of the updated analysis. Limitations include a lack of sensitivity analysis for critical assumptions and parameters influencing costs. As described in the next section, PG&E's proposed Carbon Metric framework approach attempts to build on the recommendations made by EAAC by developing alternative cost scenarios that analyze how technology costs are influenced by key assumptions and parameters. In addition, the Carbon Metric approach provides a forum for open discussion by utilizing public sources of data, bringing transparency to the process.

In subsequent economic analyses—conducted for individual AB 32 regulations —ARB has, at times, included a $/metric ton abatement cost estimate, similar in many ways to the Carbon Metric proposed in this paper.[13] However, thus far, ARB has stopped short of using these $/metric ton values to define cost-effective program measure reductions relative to cap-and-trade carbon prices.

3 The Carbon Metric – Proposed Analytical Framework

As described above, a well-defined analytical framework is needed to estimate GHG abatement cost-effectiveness in a consistent manner. The Carbon Metric framework proposed here could potentially be adopted by ARB or other stakeholders to support the development of lower cost policy, prioritization of expenditure of AB 32 related funds and industry planning.[14] This section describes the analytical construct in detail.

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[12] ARB employs a societal perspective in this analysis. Avoided criteria pollutants are valued but no value is assigned to the social benefit of avoiding greenhouse gas emissions.

[13] For example, see the $/metric ton values found in *ARB 2010b* and *ARB 2009*.

[14] This metric is not intended to replace existing methodologies used by ARB in the Scoping Plan process or regulatory proceedings. Rather, we view it as a useful supplement to the existing tools.

3.1.1 Unit Abatement Cost

The measure abatement cost (i.e., $ metric ton of GHG reduced), or the "Carbon Metric" is defined in Equation 1.

Equation 1

Where,

Net Costs

= Measure Cost Less Avoided Cost (EE, RPS, CHP and Transportation)

= Project Costs Less Incidental Revenues (Offsets)

GHG Emissions Abated

= Measure Quantity * (Avoided Emissions Intensity Less Program Measure Emissions Intensity) (EE, RPS, CHP and Transportation)

"Plausible Baseline" Emissions Less Emissions after Project (Offsets)

Both net costs and GHG abatement are calculated as net present values (NPV) in one constant year (2010 for this paper) to allow for consistent comparisons across abatement activities occurring in different years. Both the numerator and the denominator are discounted, as is done in the standard calculation of levelized cost of saved energy in the context of utility energy efficiency programs. This is done to derive an "average" single cost metric for multiple streams of investments that differ in magnitude and result in a stream of savings over a different time period.

Unit abatement costs are obtained by dividing the net present value (NPV) of the net costs by the NPV of the abated emissions . Net costs are obtained by subtracting avoided costs (or revenues) from the abatement measure costs. Abatement measure costs include costs for capital equipment, operations and maintenance (O&M), and administration. Avoided costs are primarily the total costs avoided due to lower consumption levels of electricity, natural gas or transportation fuel as a result of emissions abatement activities. Avoided costs include not only avoided fuel costs (such as natural gas) but avoided infrastructure investment costs and other costs associated with electricity, natural gas and transportation fuel consumption. In the case of offsets, net costs take into account incidental revenues from the operation of offset projects, but not revenues from the sale of offset credits.

The estimate of GHG emissions abated in the unit abatement cost equation is also in NPV over the lifetime of the project. This value is obtained by multiplying the measure quantity (for example, GWh of electricity saved through electric energy efficiency) and the net emissions intensity, i.e., the net emissions associated with one unit of measure quantity (for instance, kg CO_2e/kWh for electric energy efficiency). The net emissions intensity accounts for the fact that while some abatement measures only have avoided emissions, some measures (such as CHP) also produce emissions. The NPV methodology provides a consistent basis for comparing unit abatement costs across measures that may have different lifetimes and different timing for costs and GHG reduction over their lifetime.[15]

3.1.2 Choice of Total Resource Cost Perspective

As described in Section 2.1.1 above, estimates of abatement costs and benefits can vary depending on the perspective taken; stakeholders at different parts of the implementation cycle may incur different costs or realize different benefits. For the initial screen of the Carbon Metric framework, both costs and avoided costs (benefits) are determined on a California-wide basis using a total resource cost perspective, rather than from the participant perspective (for example, a homeowner buying an efficient car) or from that of a program administrator (for example, a utility implementing energy efficiency programs). To the extent feasible, the total resource cost does not include transfers between entities within the state.[16] The TRC is thus evaluated using a state-wide perspective, and a measure that represents a cost-effective reduction opportunity for the state may result in real costs to some entities and real savings to other entities.

To ensure that the metric is defined consistently across measures, the same types of costs and emissions should be included (or excluded) in all cases, as shown in Table AF-1 below.

[15] It should be noted that the NPV methodology obscures the actual cash flow impacts of investments in GHG abatement measures. Most measures require upfront investment costs, followed by multiple years of realized benefits. Thus, an abatement measure may be cost-effective in the long-run from an NPV perspective, but have real up-front costs associated with it in the short to medium-term.

[16] The TRC was expanded as needed to evaluate actions beyond DER.

Table AF-1: Cost and Benefits Included/Excluded in the Carbon Metric TRC and Emissions Included/Excluded

	Benefits	Costs
Benefits/Costs - Included	Monetized Benefits • Energy Savings • Transportation Savings	Total Product/Project Costs (All Funding Sources) • Capital • Operating
Benefits/Costs - Excluded	• Health Benefits • Equity Benefits • Jobs Created • Macroeconomic Benefits • Local Benefits • National Security Benefits • Land Use Benefits • Fuel Diversity Benefits	• Health Impacts • Equity "Costs" • Jobs Lost • Macroeconomic Costs • Local Costs • Land Use Opportunity Costs • Fuel Diversity Costs
	Carbon Reduced or Avoided	Carbon Created
Emissions Included	Emissions Reduced • Avoided Based on Relevant Marginal Fuel and Carbon Intensity	Emissions Created (when applicable)
Emissions Excluded	Emissions avoided from upstream operations (e.g., project construction emissions)	Non-operating emissions (Construction, Fuel Transport, etc.)[17]

3.1.3 Need for Future Work on an AB 32 Societal Cost Screen

We note that AB 32 requires consideration of overall societal benefits and costs, including reductions in other air pollutants, diversification of energy sources, and other impacts on the economy, environment and public health.[18] We propose these benefits and costs be included as a secondary societal cost screen applied only to measures with high TRC values that would otherwise not receive prioritization.[19] At least some of these excluded benefits and costs are significant for the measures analyzed and represent significant public policy issues. In applying the societal cost test it may be appropriate to use a social cost of carbon (which would likely be different than the cap-and-trade carbon price) and a lower societal discount rate. Given the fact that this issue is actively being debated in front of the CPUC[20], fully developing this societal cost

[17] For transportation, a analysis was completed on both a Tank-to-Wheels and Well-to-Wheels basis.

[18] § 38562(6) and § 38561(d) of the CA Health and Safety Code

[19] See Section 5 for full details.

[20] See *CPUC 2013* and *E3 2013.*

screen was beyond the scope of this study and we limit ourselves here to a detailed description of the initial TRC screen.

3.1.4 Time Period Analyzed

In this analysis we estimate costs and GHG reductions for measure activities implemented before the end of 2020. For the abatement value reported for each measure, we follow the Scoping Plan convention of reporting the total emissions abatement in the year 2020, rather than reporting cumulative abatement or abatement across all years studied. In contrast, as described above in the calculation of abatement cost, we utilize a net present value of cumulative reductions. Similarly, for offsets we report the cumulative reductions between 2005 (for Early Action protocols) or 2007 (for all other protocols) and 2020. In general we believe estimates of cumulative abatement are preferable to one-year snapshots as GHGs are stock pollutants and many abatement activities have different lifetimes. However, we are mindful of the fact that the statutory requirements of AB 32 require that the ARB devote special attention to the year 2020.

3.1.5 Scenarios

In this analysis, results are derived based on assumptions for abatement measure costs and associated GHG reductions. To reflect a reasonable range of credible estimates for assumptions, this study uses a scenario approach. At least two scenarios are developed for each abatement measure: one leads to a plausible, but pessimistic, outcome, with high costs and/or low abatement.[21] The other scenario leads to a plausible, but optimistic, outcome with low costs and/or higher abatement. The estimates under these scenarios do not represent the maximum and minimum bounds, but rather, a range of plausible estimates within which realized values for abatement costs and abatement potential are most likely to fall.

The scenarios are constructed by varying selected assumptions that drive cost and/or emissions abatement. There are many drivers of abatement costs and potential, and examining the impact of all of them may not be practical or feasible. Key factors should be selected based on two criteria: (1) the impact of the factor can be modeled with available resources, and (2) the factor significantly affects abatement or abatement costs.

[21] For some policy measures (e.g., EE), higher costs result in less adoption and therefore less GHG emissions mitigated compared to the low cost scenario. For other policy measures (e.g., RPS) this does not occur.

3.1.6 Common Assumptions across Abatement Measures

When evaluating the cost-effectiveness of GHG abatement across a suite of possible actions a critical step is to establish a set of common assumptions.[22] The following are examples of some of the most critical assumptions, including a description of how they were treated for the initial work contained in this document:

- *Emission Factors[23]:* Electricity emissions factors (i.e., a measure of GHG emissions per unit of electricity generated) are developed for four time-of-use (TOU) periods in 2020: summer high load hours (0.418 metric ton/MWh), summer low load hours (0.382 metric ton/MWh), winter high load hours (0.4 metric ton/MWh), and winter low load hours (0.381 metric ton/MWh). The time-weighted average of these factors is (0.400 metric ton/MWh). The emissions factor used for stationary natural gas combustion is 117 lb CO_2/MMBtu (or 0.053 metric ton/MMBtu).
- *Financial Assumptions:* All costs are represented in real 2010 dollars. Annual inflation is assumed to be 2%. The real discount rate, 5.66%, is applied to all cash flows: annual incremental costs and avoided emissions. This equates to a nominal discount rate of 7.66%, which represented PG&E's after-tax weighted average cost of capital when this study was initiated.
- *Natural Gas:* Natural gas costs came from the 2009 Market Price Referent methodology with updated futures prices, based on Henry Hub and Basis, from Dec 2010.[24] Consistent gas commodity prices were used for both the avoided gas costs & avoided electricity costs. This commodity forecast, estimated for gas delivered to the PG&E Citygate and SoCal Gas Hub, ranges from $4.60/MMBtu in 2010 to $5.48/MMBtu in 2020, in 2010 dollars.
- *Gasoline Price:* Gasoline prices are based on CEC IEPR 2012 Report's fuel price projections in California, in 2010 dollars. The gasoline prices range from $2.90/gallon to $3.20/gallon, in 2010 dollars.
- *Ethanol Price:* The baseline for ethanol fuel prices are based on a 12 month average of spot prices from Bloomberg for delivery in the Pacific region. This results in ethanol prices ranging from $1.99/gallon to $3.05/gallon, in 2010 dollars.

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[22] The common assumptions we show here document what was used for the current analysis and provide illustrative examples of the areas that need harmonization for accurate comparison across GHG abating activities. These factors should be updated for future uses of this framework.

[23] The weighted average emission factor for this analysis is 0.4 metric tons CO_2e/MWh. For the sake of comparison, this value corresponds to the emission factor of natural gas plant with a ~7,600 Btu/kWh heat rate.

[24] See *CPUC 2009*

- *Biodiesel Price:* Biodiesel prices were taken from Bloomberg, reported as a 12 month average for biodiesel rack prices in Los Angeles and San Francisco. The resulting prices ranged from $3.50/gallon to $4.50/gallon, in 2010 dollars.
- *Compressed Natural Gas Fuel Price:* CNG price ranged from $6.14/MMBtu to $6.71/MMBtu in 2010 dollars ($0.98/gallon to $1.07/gallon). Both EIA (EIA 2011) price projections and the citygate price provided by E3 were used.

3.1.7 Treatment of Interaction Effects

For the purposes of this current analysis, we chose to remove interaction effects between abatement measures in most cases. This includes the impact of carbon pricing associated with cap-and-trade (e.g., an individual evaluating the purchase of a new car will not consider higher gasoline prices that will likely result from carbon pricing).[25] This choice was made for consistency with the 2008 Scoping Plan (which did not evaluate interaction effects between measures including between cap-and-trade and other measures).

Inclusion of interaction effects between GHG abatement activities, including carbon pricing, is advisable in future uses of this framework. We recommend that portfolio assessments of various measure combinations be conducted in conjunction with consideration of the cost-effectiveness and abatement of each individual measure in isolation.[26]

4 Applying the Carbon Metric to Scoping Plan Program Measures – Description of Analysis and Initial Results

Of the five abatement measures selected for this study, the first four are program measures (or combinations of program measures) included in the Scoping Plan. The fifth abatement measure, offset credits[27], is a mechanism that provides alternative abatement opportunities for entities to meet their compliance obligations in the cap-and-trade program measure. Each measure is presented in Table IR-1 and described in more detail below.

[25] Examples of other interaction effects include: reducing the carbon intensity of the electricity generation increases the benefits of electric vehicles. Increased energy efficiency can reduce the amount of renewable resources needed to meet the RPS.

[26] The ARB already has access to analytic tools (such as the model known as Energy 2020) that are well-suited to evaluate measures as a portfolio.

[27] Offsets are generated by the removal, reduction, or sequestration of GHGs not directly covered under the cap-and-trade program.

Table IR-1: AB 32 Program Measures Evaluated

Program Measure	Measure Target (s)	Reference Point for this Analysis	Consultant
Energy Efficiency	• 18,800 GWh and 172 Mth demand reduction by 2020	• Incremental from 2011 Integrated Energy Policy Report	E3
Renewable Energy	• 33% of retail electricity sales by 2020	• Incremental from 20% RPS	E3
Low Carbon Fuel Standard	• 10% reduction in carbon intensity; Fleet average (weighted) tailpipe emission standard of 166 gCO_2/mile by 2025; Large volume auto manufacturers to sell 15.4% zero emission vehicles by 2025	• Incremental from Pavley I, includes some assumed impact of the Pavley 2 and ZEV components of the Advanced Clean Car program	ICF
Combined Heat and Power	• 4,000 MW by 2020	• Incremental from 2011 Levels	E3
Offsets	• 218 MMT cumulatively by 2020 (8% of compliance entities' compliance obligation)	• Offsets developed since 2005	DNV

- Energy Efficiency: The 2008 Scoping Plan set statewide energy efficiency (EE) estimates for both electricity and gas. Major policies helping to achieve these estimates include: (1) utility-run EE programs , (2) federal/state building codes and appliance standards and (3) efforts to promote water system efficiency.
- Renewable Portfolio Standard : California law S B1 2X of 2011 requires 33% of retail electricity sales in California to be met by renewable generation by December 31, 2020 and maintained thereafter.
- Low Carbon Fuel Standard : The Scoping Plan includes the following major transportation measures: (a) Low Carbon Fuel Standard (LCFS), requiring a 10% reduction in the carbon intensity (i.e., emissions per unit of fuel)[28] of transportation fuels by 2020, (b) Zero Efficiency Vehicle (ZEV) regulation which will require large volume manufacturers to sell a certain percentage of ZEVs each year, and (c) Pavley 2 mandate, i.e., the GHG emissions portion of the ARB's Advanced Clean Cars program, assumed to be consistent with the federal light duty fuel economy standard of a fleet average o f 54.5 miles per gallon (mpg). In this analysis we primarily study the LCFS and assume compliance with ZEV and Pavley 2.

[28] LCFS carbon intensity is defined as the amount of life-cycle (well-to-wheels) GHG emissions reported in grams of CO_2 equivalent per megajoule.

- Combined Heat and Power (CHP): The Scoping Plan includes a 2020 statewide CHP abatement estimate. The major programs contributing toward this estimate include: the CPUC approved QF/CHP Settlement approved in D.10-12-035, the Self Generation Incentive Program (SGIP), and AB 1613 (Stats. 2007, Ch. 713, known as the "Waste Heat and Carbon Emissions Reduction Act").
- Offsets: The Cap-and-Trade regulation allows compliance entities to use eligible offsets to meet up to 8% of their compliance obligation for each compliance period.

PG&E retained the following consultants to conduct this initial demonstration of concept Carbon Metric analysis: Energy and Environmental Economics (E3) for EE, RPS, and CHP; Det Norske Veritas (DNV) for Offsets; and, ICF International for the LCFS. The following sections summarize the analysis for each of the five selected abatement measures along with a discussion of the key factors and results for abatement cost and abatement potential. A full consultant report is available for each measure analysis which provides additional detail.[29]

4.1 Energy Efficiency

4.1.1 Analysis & Key Assumptions

The unit abatement costs ($/metric ton) of EE measures are estimated using Equation 1, i.e., by estimating net cost of implementing EE measures ($) and dividing by net GHG abatement (Metric ton). The EE analysis addresses three general categories of EE activity in California: utility programs; water system efficiency; and building energy codes and appliance standards.[30] Each of these three measure categories are summarized below:

- Utility programs: Investor Owned Utility (IOU) and Publicly Owned Utility (POU) programs that target the major end-uses across industrial, residential and commercial building sectors. They include, for example, advanced new construction, energy efficient lighting, HVAC replacements and operational improvements, efficient refrigerators, industrial motor replacement, and building envelope improvements (such as window replacements and insulation). Emerging technology measures, such as LED street lighting and behavioral energy efficiency are also considered.

  Energy savings and cost data for efficiency programs within IOU service areas are taken from the 2012 Navigant EE potential study[31]. More specifically, we used the "market

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[29] If the reader is interested in these underlying reports and has not yet received a copy please contact Ray Williams at PG&E (ray.williams@pge.com or 415-973-3634).

[30] We do not attempt to anticipate updates or changes to the existing energy efficiency programs, nor do we attempt to consider the total supply curve of potential abatement from energy efficiency.

[31] "Analysis to update energy efficiency potential, goals, and targets for 2013 and beyond", (hereafter referred to as the 'Navigant study')

potential" assuming a 50% incentive level [32] for both the high and low cost scenarios. This market potential relies on a consumer adoption model that takes into account retail rates and assumed energy efficiency inventive levels; the costs include administrative and incremental measure costs. POU efficiency potential and costs are extrapolated from IOU potential and costs, based on data in the 2009 CEC report *Statewide Energy Efficiency Potential Estimates and Targets for California Utilities*.[33]

- Water system efficiency: Water system efficiency is efficiency realized in the areas of water supply, conveyance, treatment, distribution, and wastewater treatment. Actions likely to be adopted include optimizing pump operation, replacing pump motors and pumps, and installing variable frequency drives with appropriate sensors and control algorithms.
- Building energy codes and appliance standards: codes and standards incremental to the 2011 IEPR baseline from a combination of state (T-20, T-24, Reach Code) and federal regulations addressing building shell, appliance, and lighting measures. We utilized the Navigant codes and standards spreadsheet model, developed by Heschong Mahone Group (HMG), which accompanies the 2011 Navigant potential study to estimate statewide energy savings. We estimated codes and standards costs from a separate model, also developed by HMG, that incorporates costs from case studies performed for the CEC (by HMG) and evaluation of federal rulemakings for federal appliance standards (by Energy Solutions).

We calculated incremental costs at different target levels within each scenario — 4,000, 8,000, 12,000, 16,000, 20,000, 24,000, 28,000, and 32,000 GWh for electricity; and 100, 200, and 300 Mtherms for natural gas. We term each successive bundle of measures a "tranche" — e.g., 4,000 GWh worth of measures that moves the level of achievement towards the estimate from 4,000 GWh to 8,000 GWh, from 8,000 GWh to 12,000 GWh and so on. Each tranche reflects a grouping of energy efficiency measures. We then calculate the incremental net carbon cost of each successive tranche. Measures are placed into the respective tranches based on their costs in terms of $/tonne. This ordering by costs roughly follows energy efficiency program design, in which estimates and budgets are largely set based on surveying cost effective measures. For purposes of this report, the curves intentionally do not include positive-cost tranches because these are interpreted to be inconsistent with current energy efficiency utility program planning practices, which emphasize portfolio level cost-effectiveness.[34]

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[32] This indicates that 50% of the incremental cost of the measures is paid for through utility incentive programs.

[33] *CEC 2009*

[34] We show no positive-cost abatement as it is unlikely to be targeted under current programs and is not fully captured in the Navigant model. We note that higher cost measures are sometimes promoted through market transformation programs. However, these programs constitute small fractions of overall energy efficiency program portfolios and we did not explicitly capture this element of energy efficiency.

4.1.2 Key Factors and Scenarios

Table EE-1 shows the key factors that we varied, and our choices for these assumptions, to develop our optimistic and pessimistic scenarios.

Table EE-1: Energy Efficiency Key Factors and Assumptions

EE Key Factors and Assumptions	Electricity (E) or Natural Gas (NG)	High Cost, Low Abatement Scenario	Low Cost, High Abatement Scenario
Measure market transformation (Navigant measure cost adjustment factor)	E, NG	100%	85%
Measure technology performance (savings adjustment)	E, NG	ex-post savings (~80% of ex-ante savings)	ex-ante savings
Advanced new construction: homes and buildings energy efficiency achievements	E, NG	Navigant Level 1 (15% better than 2005 Title 24)	Navigant level 3 for residential, level 2 for non-residential (30% and 25% better, respectively, than 2005 Title 24)
Level of savings achieved through behavioral EE measures	E	0 GWh in 2020	132 GWh in 2020
Level of savings achieved through water system efficiency	E	1,100 GWh in 2020	4,400 GWh in 2020
Interactive effect (reduced waste heat from electric lighting increases natural gas use)	NG	Included	Excluded

program design in this analysis. We also believe that additional negative and positive cost abatement is achievable from EE activities beyond what the incentive levels in current programs achieve.

4.1.3 Initial Results

Tables EE-2A and EE-2B summarize the estimates for abatement and abatement cost for GHG reduction from Energy Efficiency measures for Electricity and Natural Gas respectively. Abatement and abatement cost estimates are presented for the Low Cost and High Cost scenarios, and for increasing total levels of energy efficiency achieved in 2020.

Table EE-2A: Abatement and Abatement Cost for Electric EE - Results

Scenario	0-4,000 GWh	4,000-8,000 GWh	8,000-12,000 GWh	12,000-16,000 GWh	16,000-20,000 GWh	20,000-24,000 GWh	24,000-28,000 GWh	28,000-32,000 GWh
High cost	($179)	($162)	($116)	($94)	($49)	($4)		
Low cost	($181)	($165)	($136)	($123)	($106)	($94)	($77)	($30)
High cost	1.6	3.1	4.7	6.2	7.8	9.4		
Low cost	1.6	3.1	4.7	6.2	7.8	9.4	10.9	12.5

Electricity: As seen in Table EE -2A, in the low cost scenario there is roughly 32,000 GWh of cost effective energy efficiency, while in the high cost scenario, there is roughly 24,000 GWh of cost effective energy efficiency. Assuming an AB 32 Scoping Plan estimate of 18,800 GWh (adjusted for consistency with the IEPR 2011 basel ine), the estimate appears reachable in both the high and low cost scenarios and at negative cost. The average unit abatement cost is $(101)/metric ton for 9.4 million metric tons of CO_2 of GHG reductions under the High Cost scenario and $(114)/metric ton for 12.5 million metric tons of CO_2 of GHG reductions under the Low Cost scenario.

Table EE-2B: Abatement and Abatement Cost for Natural Gas EE - Results

Scenario	0-100 MTherm	100-200 MTherm	200-300 MTherm
High cost scenario	($124)	($108)	($5)
Low cost scenario	($126)	($115)	($83)
High cost	0.5	1.0	1.6
Low cost	0.5	1.0	1.6

Natural gas: As seen in Table EE -2B, in both the low and high cost scenario, there is roughly 300 MTherms of cost effective energy efficiency. Assuming an AB 32 Scoping Plan estimate of 170 MTherms (consistent with the IEPR 2011 basel ine), the estimate appears reasonable in both the high and low cost scenarios and at negative cost. The average unit abatement cost is $(79)/metric ton under the High Cost scenario, and $(108)/metric ton under the Low Cost scenario, both for 1.6 million metric tons CO_2 of GHG reductions.

4.1.4 Takeaways

Our study estimates a combined electric and gas energy efficiency abatement potential range of 11 million metric tons CO_2 to 14.1 million metric tons CO_2 in 2020 based on our high and low cost scenarios; these estimates are for actions generally consistent with current state energy policy and programs, namely assumed IOU & POU program incentive levels, adopted codes and standards and cost-effective utility program design. Both the high and low estimates of abatement potential are greater than our approximation of an updated ARB Scoping Plan energy efficiency estimate of 9.1 million metric tons CO_2. The vast majority of the estimated abatement potential is in electricity savings (9.4 - 12.5 metric ton). The major components of the energy efficiency savings are utility programs (both IOU and POU) and building energy codes and appliance standards for both electricity and natural gas. On the electricity side, water system efficiency improvements also make significant contributions towards statewide energy savings, if they are achieved at the levels set in the Scoping Plan. The cost of achieving GHG emissions reductions through EE measures examined by this study is estimated to be negative.

In order to achieve the EE abatement forecasted from these programs we recommend continued support of existing utility-run efficiency programs. Any change to the administration of such programs could jeopardize the total abatement achieved by 2020. Potentially, additional funds from Proposition 39 and cap-and-trade revenue could be used to supplement existing utility program budgets. We also support efforts to continually improve compliance with codes and standards and to quantify water system energy efficiency potential and target these savings through coordinated stakeholder efforts.

4.2 Renewable Electricity Generation

4.2.1 Analysis and Key Assumptions

The analysis to estimate the cost of abatement from increasing renewable electricity generation—starting at 20%, and building out to 33% in 2020—uses the 33% RPS Calculator, a tool developed for the CPUC by E3[35] that contains information on renewable costs and generation potential and estimates the environmental and economic attributes of different

[35] Resources included in the 33% RPS Calculator include commercial projects, resources in California identified by the Renewable Energy Transmission Initiative (RETI), Western Renewable Energy Zone (WREZ) resources in the rest of the Western Electricity Coordinating Council (WECC), and distributed generation (DG) resource potential estimates. The RPS Calculator ranks resources on cost (including transmission costs), commercial interest (actual projects are prioritized over generic resource types and locations), environmental sensitivity, and timing (anticipated online date), and finally uses these rankings to select resources to fill the renewable net short based on cases of different weightings.

renewables development scenarios [36]. The starting point for the analysis is the Trajectory Case renewable energy portfolio scenario originally developed by the CPUC, representing a balanced weighting of considerations between cost, environmental impact, and commercial reality. The following adjustments are made to the Trajectory Case to better reflect current policy and market conditions:

- Add 1,384 MW of small-scale solar PV, reflecting signed utility solar PPA's (384 MW) as well as authorized Renewable Auction Mechanism (RAM) procurement (1,000 MW).
- Update transmission costs and capacity consistent with the 2011-2012 CAISO Transmission Plan.
- Switch four projects from solar thermal to photovoltaic technology, based on announcements from the developers of these projects[37].

Using the updated and modified Trajectory Case, the unit abatement cost ($/metric ton) for the 33% RPS mandate is calculated using Equation 1, i.e., by estimating net cost of developing renewable technologies ($) and dividing by net GHG abatement (metric tons). The unit abatement cost associated with getting to lower levels (25% and 30%) of renewables in 2020 is also estimated.

Both the Federal Investment Tax Credit (ITC) and Production Tax Credit (PTC) are assumed to be in effect through 2020 [38]. We assume that renewable resources eligible for ITC will receive a 30% credit realized in the year in which a project begins commercial operations and that resources eligible for PTC will receive credit throughout their operating life.

4.2.2 Key Factors and Scenarios

Two key factors are analyzed to determine a plausible range for unit abatement costs: (1) learning effects from increasing installed capacity, leading to lower generation costs, and (2) increased integration costs resulting from the need for ancillary services to integrate intermittent renewable resources into the power grid. Table RE-1 shows the assumptions for the High Cost and Low Cost scenarios and the correlation between selected factors and unit abatement costs.

[36] E3's RPS calculator version 1.3 was used for this analysis.

[37] Imperial Valley Solar (formerly Stirling Solar Two); Stirling Solar One; CA Solar 10, Palen Solar; Ridgecrest Solar I, Solar Millennium

[38] The ITC is currently available to qualified projects that are placed in service prior to the end of 2016, though the geothermal credit has no expiration date, and the solar credit will (unless otherwise extended) revert to 10%, rather than expiring altogether, at the end of 2016. PTC is currently avalable to wind projects placed in service before the end of 2012, and to other renewable technologies placed in service before the end of 2013.

Table RE-1: Renewables Key Drivers and Scenarios

Renewables Key Factors for Unit Abatement Cost	Correlation with Unit Abatement Cost	High Cost Scenario	Low Cost Scenario
Learning Effects	Negative	None[39]	As in table RE-2
Integration Costs	Positive	$7.50/MWh[40]	$3.75/MWh

Learning Effects and Impact on Costs: When projecting costs out to 2020 under the High Cost scenario, a learning effect is factored in to represent the benefit from "learning" by the industry as global installed capacity increases. For a given technology, the reduction in costs with increase in capacity is a function of the learning rate for that technology. The learning rate is defined as the percentage reduction in capital costs associated with a doubling in capacity and is derived from existing literature [41]. Learning rates are only applied to a portion of the total capital cost to reflect the fact that learning benefits are not likely to decrease costs across the entire power plant, but rather across specific components. Table RE-2 shows the learning rate assumptions.

Table RE-2: Learning Rates for Renewable Technologies

Learning Curve Assumptions	Biomass	Solar PV	Solar Thermal	Wind	Other[1]
Learning Rate (% reduction in capital cost for doubling in capacity)	10%	20%	8%	10%	0%
% of Capital Cost to which Learning Rate is applied	50%	85%	85%	50%	N/A

[1] Other includes biogas, geothermal and hydro

Because energy technology manufacturing and development is a global market, learning effects are modeled as a function of worldwide installed capacity estimates, derived from *IEA 2008*.

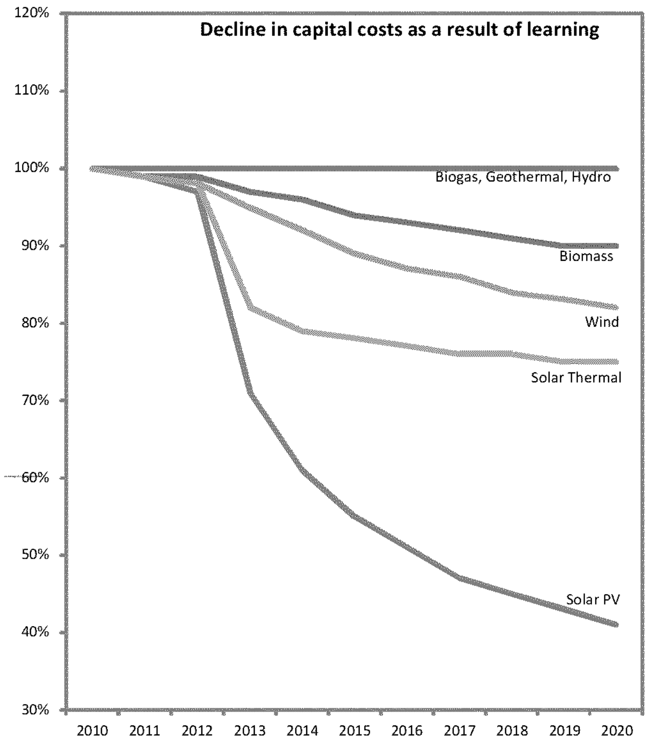
[39] This assumption reflects the plausibility of learning related cost declines not being realized either because of no technology learning effects from scale or because of the inability of suppliers to capture or provide these price declines after contracts are in place.

[40] $7.50/MWh is the estimated integration cost for a 40% intermittent resource penetration, based on a regression analysis of 32 estimates of wind integration costs from various studies on North American utilities.

[41] *McKinsey 2008* and *Enermodal 1999*

Figure RE-1 shows the results of learning rates applied to capital costs starting from 2010, and the resulting LCOEs in 2010 and 2020.

Figure RE-1: Decline in Renewable Resource Capital Costs & Associated LCOE



Levelize Cost of Technology $/MWh

	2010	2020
Biogas	$115	$115
Geothermal	$121	$121
Hydro	$196	$196

	2010	2020
Biomass	$128	$119

	2010	2020
Wind	$99	$80

	2010	2020
Solar thermal	$202	$161

	2010	2020
Large Scale Solar PV	$157	$78
Small Scale Solar PV	$284	$145

All values are in $2010

4.2.3 Initial Results

Figures RE-2 and RE-3 show the unit abatement cost ($/metric ton) and associated abatement potential of building up to three renewables levels in 2020: 25%, 30% and 33%, the last of which complies with the current mandate. The 33% mandate is achieved with an average unit abatement cost of $149/metric ton and $201/metric ton under the Low Cost and High Cost scenarios, respectively. The total GHG reduction moving from 20% RPS to 33% RPS level is estimated to be 12.9 million metric tons.

SB_GT&S_0767252

Figure RE-2: Unit Abatement Cost for Renewables – Low Cost Scenario

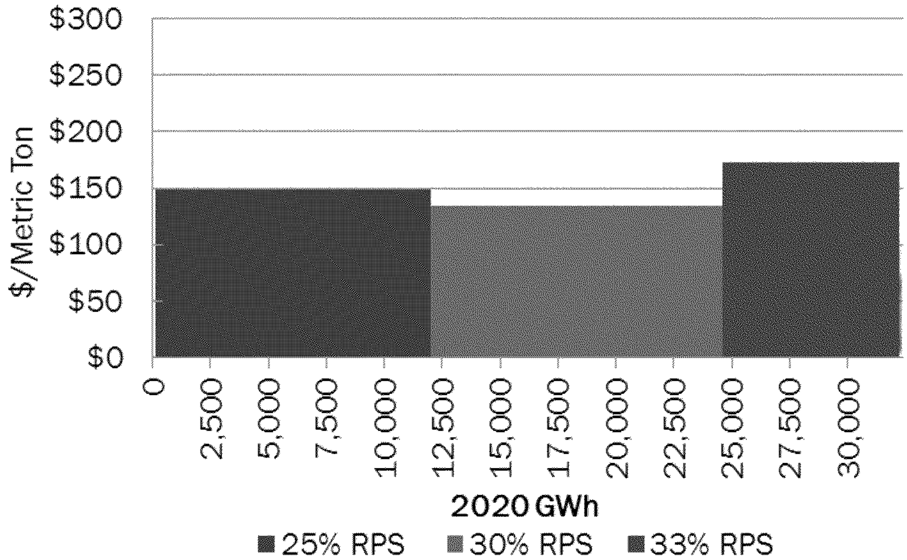
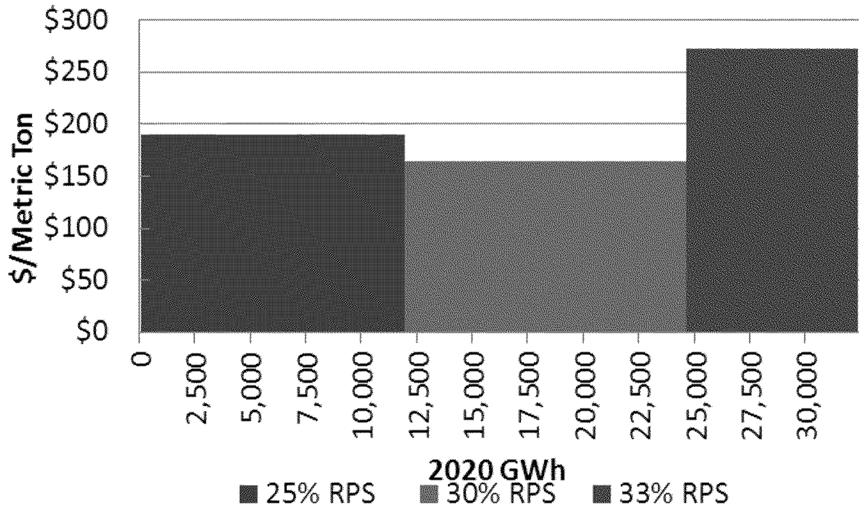


Figure RE-3: Unit Abatement Cost for Renewables – High Cost Scenario



As seen in Figure RE-2 and RE-3, the unit abatement costs decrease as the share of renewable generation increases from 25% to 30%, and then increases as the renewable generation goes from 30% to 33%. This trend is a result of the resource mix selected to provide increasing levels of renewable generation. The resource mix at the 25% renewable level includes existing solar thermal and some large scale solar PV projects which, while relatively expensive, are selected by the RPS calculator's ranking method ology because of their shorter time to market and high commercial interest scores. The increase in renewable generation level from 25% to 30% is achieved through the inclusion of relatively low cost wind projects, resulting in a drop in unit abatement costs. Increasing the renewables level t o 33% requires the inclusion of higher cost renewable projects, such as solar thermal requiring new transmission, because the lower cost projects are not sufficient to meet the goal; this results in an increase in unit abatement cost.

4.2.4 Takeaways

The cost of achieving GHG reduction through deployment of renewable technologies varies based on the key factors modeled. The Low Cost scenario assumes significant cost benefits from learning effects. The extent to which learning benefits are realized depends on the following factors: worldwide growth in installed capacity of renewables, the actual learning rates for each technology and the ability, or lack thereof, to capture technology cost declines after fixed price contracts have been signed for a significant portion of the 33% goal. A second factor that can decrease unit abatement costs from renewables is system integration costs, which can be lowered by finding ways to integrate renewables into the grid with lower cost investment in dispatchable resources and by improving forecasting and scheduling of renewable generation. We believe updated analysis may be necessary to improve understanding of delivered RPS costs—technology cost declines, integration costs and transmission costs—and to position California for more affordable design of any future RPS expansion.

4.3 Low Carbon Fuel Standard

4.3.1 Analysis and Key Assumptions

The analysis of the transportation sector evaluated the feasibility and cost of abatement of California's Low Carbon Fuel Standard (LCFS) regulation. Under the LCFS, the ARB requires fuel producers to reduce carbon intensity of gasoline and diesel by ten percent by 2020, where carbon intensity is measured in grams per unit energy of fuel (gCO_2e/MJ) consumed on a full-fuel cycle or well-to-wheel basis. The LCFS does not stipulate how to reduce carbon intensity, rather it uses a crediting approach to require transportation fuels providers meet periodic intensity standards. Fuels that are less carbon-intensive than the standard will generate credits whereas fuels more carbon-intensive than the standard will result in deficits.

Compliance with the LCFS regulation can be achieved through the use of alternative fuels and/or advanced vehicles. Alternative fuels include ethanol (corn, sugarcane and cellulosic), biodistillates (waste oil, canola, soybean and cellulosic), Compressed Natural Gas (CNG), electricity and hydrogen. Advanced vehicles include flex-fuel, CNG, hybrids, plug-in hybrids, battery electric, and fuel cell vehicles.

The change in the light-duty vehicle fleet due to the Pavley 2 program measure and the Zero Emissions Vehicle (ZEV) mandate were factored into feasibility analysis of LCFS. We assumed that the Pavley 2 standard and ZEV are met up to 2020 through increased market penetration of more efficient vehicles and ZEV eligible vehicles (and that the costs of conventional vehicles increase over time to comply with the standard).[42]

[42] ZEV penetration is assumed to match ARB's "most likely compliance scenario" for the ZEV regulation.

Analysis Details: To analyze the feasibility and cost of the aforementioned alternatives, ICF developed an optimization model that considers a variety of compliance strategies based on each fuel's costs, incremental to gasoline or diesel, and its abatement potential. The model dynamically solves for a low-cost, lowest emission solution while considering inter-temporal trading and banking behavior. This banking is a critical aspect of the LCFS program because it provides an incentive for over-compliance in the early years of the regulation, when compliance strategies are potentially less costly.

ICF modeled LCFS compliance using the LCFS program's deficit and credit system i.e., fossil gasoline and diesel consumption yielded deficits and the introduction of lower carbon fuels yielded credits. Any fuel with a carbon intensity above the baseline for that year generated deficits and any fuel with a carbon intensity below the baseline for that particular year generated credits.

In this analysis, we developed two scenarios—a plausible low cost and plausible high cost scenario. For each scenario, we identified variables across three broad categories—fuel costs, vehicle costs and infrastructure costs and varied those variables with the greatest uncertainty and market impact.

The determination of unit abatement costs associated with the two scenarios to meeting mandates requires the estimation of annual costs and GHG reduction under each approach, from 2011 to 2020. The key steps for this estimation are:

- Project vehicle population over 2011-2020 i.e., total number of vehicles by age, class and fuel/technology type, for each calendar year, needed to comply with mandates.
- Determine fuel consumption for each fuel type based on assumptions for vehicle miles travelled (VMT) as a function of vehicle age and class and fuel economy estimates by vehicle class and fuel/technology type.
- Multiply fuel consumption by the appropriate emission factors to yield emissions.
- Combine fuel consumption and vehicle sales data to yield total fuel costs, vehicle and infrastructure costs for each analysis year. Infrastructure costs are incurred to allow the increased use of alternative fuels.[43]

The three main categories of assumptions are GHG emission factors, fuel costs, and infrastructure costs.

[43] Infrastructure costs are developed for: electricity (cost of charging infrastructure), ethanol (cost of cellulosic ethanol plants, cost of trucks to transport ethanol from marine/rail terminals or production plants to petroleum terminals and cost of upgrades to petroleum terminals to handle and store increase volumes of ethanol), CNG (home refueling cost and CNG refueling station costs) and hydrogen (cost of production plants, trucks for transportation and refueling stations).

GHG Emission Factors: Annual GHG abatement is estimated on both a full fuel cycle (on a well-to-wheel (WTW) basis [44]) and on a tank-to-wheel (TTW), or vehicle only, basis. For TTW estimates, emissions from electricity and hydrogen are typically assumed to be zero; however for this analysis, emissions factors consistent with other Carbon Metric work streams are used. The emissions factors utilized in this analysis were obtained from ARB's LCFS Lookup tables.

Fuel Costs: To calculate unit abatement costs, we focused on rack prices—the price that finished liquid fuels (e.g., gasoline, diesel, ethanol) are sold into the retailers market. The rack price is the baseline for comparison because the finished fuel, ethanol or biodiesel, will be traded at some commodity price independent of the feedstock. This choice was made to be consistent with the total resource cost perspective because the majority of low carbon fuel production is expected to occur outside of California. Table TR-1 below shows a summary of the assumptions sources for fuel GHG emission factors and costs.

Infrastructure Costs: We incorporated costs incurred to allow the increased use of alternative fuels. We developed the infrastructure costs for increased ethanol, biodiesel, CNG, electricity and hydrogen consumption. In the case of ethanol, we considered the cost of installing new stations, cost of retrofitting existing stations, and the ratio of building new stations to the ones that were retrofitted. In the case of biodiesel, we accounted for the required expansion of biodiesel storage at petroleum terminals and refueling stations for B20. In the case of Plug-in Electric Vehicles, we considered the costs of installing Electric Vehicle Supply Equipment (EVSE) at residential and non-residential applications. We did not consider any transmission and distribution reinforcement costs in this analysis.

[44] For petroleum fuels, WTW emissions include emissions associated with crude oil recovery, pipeline transport to the refinery, refining, transport to refueling stations and combustion in the vehicle. For natural-gas fired combined cycle electricity production, WTW emissions include recovery and transport of natural gas to the power plant, combustion of the fuel and losses in transmission and distribution.

Table TR-1: Transportation Fuel Cost Assumptions and Carbon Intensities

Fuel	Base Cost Assumptions – Fuel	Carbon Intensity (in gCO_2e/MJ)	
		WTW	TTW
Gasoline Blendstock (CARBOB)	\$2.90/gallon to \$3.20/gallon (CEC price forecast)	99.18	72.90
Ultra Low Sulfur Diesel	\$3.05/gallon to \$3.40/gallon (CEC price forecast)	98.03	74.10
Ethanol, US Corn	\$1.99/gallon to \$3.05/gallon (12 month average of spot prices at the rack, derived from Bloomberg)	86.46	0
Ethanol, CA Corn	Same as US Corn ethanol	80.70	0
Ethanol, Brazil Sugarcane	\$2.25/gallon to \$3.70/gallon (12 month average of spot prices at the rack, derived from Bloomberg)	68.84	0
Ethanol, Cellulosic	Same as Brazilian ethanol	29.00	0
Biodiesel, Soybeans	\$3.50/gallon to \$4.50/gallon (12 month average of spot prices at the rack, derived from Bloomberg)	83.25	0
Biodiesel, FOGs	Same as Soybean biodiesel	15.04	0
Biodiesel, Corn Oil	Same as Soybean biodiesel	4.00	0
Renewable Diesel, FOGs	Same as Soybean biodiesel	29.49	0
Renewable Diesel, Cellulosic	Same as Soybean biodiesel	37.20	0
Compressed Natural Gas	Citygate pricing (CEC and AEO projections)	68.0	55.7
Electricity	Retail electricity rates for EV charging from major utilities	41.30	31.9
Hydrogen	Utilized current cost from Sunline Transit and escalated each year with NG costs	57.80	32.0

4.3.2 Key Factors and Scenarios

Annual emission reductions and costs are estimated for each measure from 2011 through 2020 on an overall basis and by fuel/technology type . The cost components included in the Carbon

Metric are fuel, vehicle and infrastructure costs that are incremental to the baseline.[45] Table TR-2 shows the key factors analyzed to determine a plausible range for unit abatement costs and abatement potential in order to develop the High Cost and the Low Cost scenarios.

Table TR-2: Transportation Key Factors and Scenarios

Fuel / Strategy	Cost Element	Low Cost Case	High Cost Case
Ethanol, E10 Fuel costs [a]	Corn ethanol, lower CI	+2-4 ¢/gallon	+4-6 ¢/gallon
	Sugarcane ethanol	+26 ¢/gallon	+74¢/gallon
	Cellulosic ethanol	+50 ¢/gallon (decreasing in 2015)	+150 ¢/gallon
Ethanol, E85 Refueling Equipment	Retrofits	$125,000	$150,000
	New stations	$300,000	$375,000
	Ratio of retrofits to new stations	40/60	20/80
Biodiesel, Fuel Costs [b]	Soy	--	--
	Corn oil	+25 ¢/gallon	+50 ¢/gallon
	FOGs	+25 ¢/gallon	+50 ¢/gallon
Biodiesel, Infrastructure Costs	Refueling infrastructure	$70,000	$100,000
	New stations	$200,000	$250,000
	Terminal storage	$120 million	$200 million
Renewable Diesel, Fuel Costs [b]	FOGs	+50 ¢/gallon	+100 ¢/gallon
	Cellulosic/waste	+50 ¢/gallon	+100 ¢/gallon
Natural Gas, Vehicle Costs	CNG, LNG vehicles	10 percent reduction by 2020	No vehicle price reductions
PEVs eVMT, vehicle costs, infrastructure costs	Electric vehicle miles traveled, PHEVs	+5 percent per year	+3 percent per year
	Vehicle costs	30% reduction by 2020	10% reduction by 2020
	Federal tax credit	Available through 2020	Phased out post-2018
	EVSE costs, L2 residential	$900	$2,350
	EVSE costs, L2 nonresidential	$2,500	$7,000
	EVSE costs, DC fast charging	$12,500	$20,000
Hydrogen FCVs	Vehicle costs	25% reduction by 2020	10% reduction by 2020

a. The cost increases for ethanol are relative to average corn ethanol, US.
b. The cost increases for biodiesel and renewable diesel are relative to biodiesel produced from soybeans.

[45] For example, for cellulosic ethanol, we quantify the net cost increase relative to consuming the equivalent amount of gasoline. In this case, there are no incremental vehicle costs, but we add incremental infrastructure costs such as cellulosic ethanol production plants, new trucks required to transport the ethanol to petroleum terminals, and upgrades to storage and blending equipment at the petroleum terminals. We also include costs associated with adding refueling infrastructure.

4.3.3 Initial Results

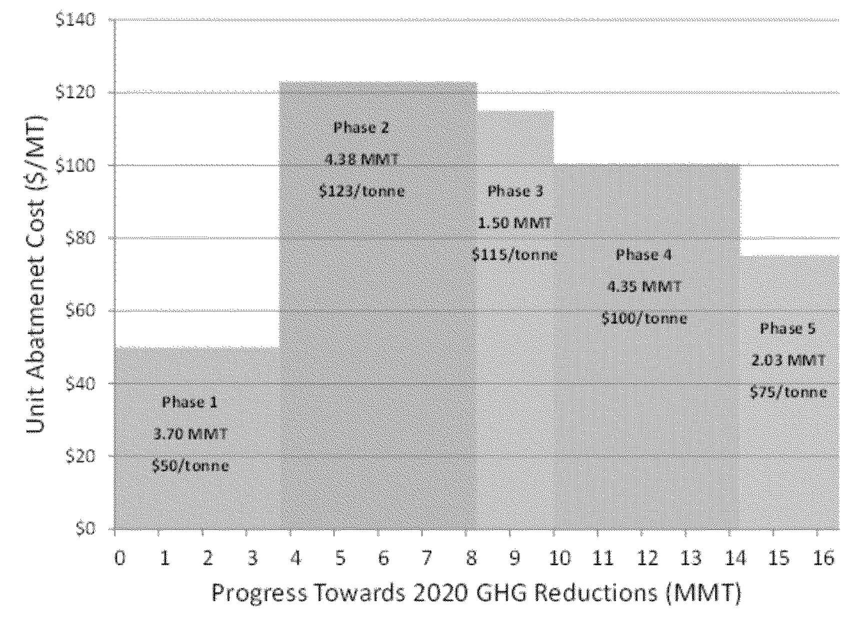
The following subsection presents the findings based on a plausible low cost scenario and a plausible high cost scenario. Compliance is defined as a net zero balance of credits in 2020. Table TR-3 shows the abatement potential and unit abatement cost unde r both scenarios on a WTW and a TTW basis. While WTW estimates are more commonly used in the transportation industry, the TTW method is consistent with the analysis for other abatement measures, and allows for more meaningful comparisons. The specific phases correspond to specific ye ars with different carbon intensity reduction targets in the regulation (1% by 2013; 2.5% by 2015 ; 5% by 2017; 8% by 2019 and 10% 2020). Actual carbon intensity exceeds targets in the years that credit banking occurs.

Table TR-3: Carbon Metric Estimates for the Low Carbon Fuel Standard

Phases	Plausible Low Cost				Plausible High Cost			
	Reductions (in MMT CO_2e)		Costs (in $/MT)		Reductions (in MMT CO_2e)		Costs (in $/MT)	
	WTW	TTW	WTW	TTW	WTW	TTW	WTW	TTW
Phase 1 2011-2013	3.74	10.09	$50	$8	3.35	8.57	$85	$10
Phase 2 2013-2015	8.13	12.25	$123	$70	7.19	9.91	$202	$25
Phase 3 2015-2017	9.85	12.88	$115	$40	8.83	11.99	$219	$69
Phase 4 2017-2019	14.22	16.09	$100	$33	12.91	12.61	$209	$110
Phase 5 2019-2020	16.27	17.64	$75	$70	14.94	14.91	$219	$157
Average Unit Abatement Cost			**$94**	**$39**			**$182**	**$79**

SB_GT&S_0767259

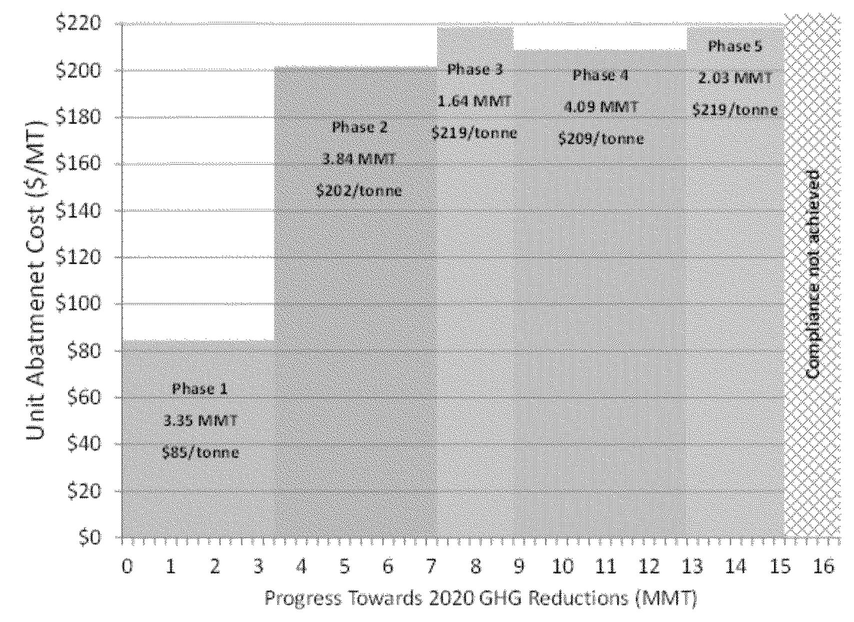
Figure TR-1: Abatement and Abatement Cost by Phase from the LCFS – Low Cost Scenario



Low Cost Scenario: Compliance with LCFS is achieved in the Low Cost Scenario at an ave rage unit abatement cost of $94/metric ton and with a total abatement potential of 16.27 million metric tons in 2020. LCFS compliance in the low cost scenario depends heavily on over -compliance in the diesel pool and the ability to bank credits across compliance years.

The unit abatement costs include more significant investments in alternative fuel infrastructure in the earlier years in advance of more significant fuel deployment. These investments are required for E85, biodiesel, electric vehicles, CNG and LNG. Also, the cost of advanced vehicles decreases over time. In the case of PEVs, battery improvements and volume manufacturing contribute to a 30 percent decrease by 2020 while in the case of NGVs, the increased vehicle manufacturing volumes and modest improve ments in cylinder technologies yield a 10 percent decrease by 2020.

Figure TR-2: Abatement and Abatement Cost by Phase from the LCFS – High Cost Scenario



High Cost Scenario: Compliance with LCFS is barely missed in the High Cost Scenario in 2020. The average unit abatement cost is $1 82/metric ton and with a total abatement potential of 14.94 million metric tons in 2020. LCFS compliance in the high cost scenario depends heavily on over-compliance in the diesel pool and the ability to bank credits across compliance years.

The primary driver for the increase in unit abatement costs per metric ton in the high cost scenario is Plug-in Electric Vehicles (PEVs). Although PEVs account for only about 4 percent of GHG reductions in 2020, they account for about 2 0 percent of the costs. Other factors that lead to higher unit abatement costs are the costs of Brazilian sugarcane ethanol and corn -oil based biodiesel and reduced availability of cellulosic ethanol. There is also lesser investment in infrastructure in the earlier years which leads to a shortfall of credits in the later years.

4.3.4 Takeaways

Following are the key takeaways from the analysis:

- Both scenarios rely significantly on over -compliance out to 2016 to comply by 2020 and there is limited variation in the quantity of abatement across the two scenarios.
- GHG reductions in the diesel pool using alternative fuels with high abatement potential such as corn-oil based biodiesel, renewable diesel and natural gas can help make up for a shortfall of credits in the gasoline pool.

- Compliance with LCFS beyond 2020 will likely be challenging because of the number of deficits generated in the year 2020 and the reliance on banked credits to help with compliance in the year 2020.
- The Zero Emissions Vehicle (ZEV) mandate does not come into effect until 2017 and makes a small contribution towards LCFS compliance largely because of the methodology used to calculated credits generated by electricity and hydrogen. In most cases, one LCFS credit is equivalent to one metric ton of GHGs reduced; however, in the case of electricity and hydrogen displacing gasoline in the light-duty sector, for instance, the credits generated are a factor of 3.4 and 2.5 higher than the GHG reductions, respectively. This is a result of the calculation that CARB uses to determine LCFS credits.
- Advanced biofuels, such as sugarcane ethanol and corn-oil based biodiesel, play a major role in compliance with LCFS based on the forecasted availability of supply, pricing and low carbon intensity. Natural Gas Vehicles (NGVs) will have higher penetration in the medium duty vehicles segment and generate a greater portion of the credits whereas Plug-in Electric Vehicles will continue to generate a small portion of the LCFS credits.
- The LCFS regulation will have a modest impact on retail fuel prices due to increased costs associated with biofuel blending and the potential exposure to the LCFS credit market.
    - In the low cost scenario, gasoline prices will increase by $0.06 to $0.26 per gallon and diesel prices will increase by $0.32 per gallon.
    - In the high cost scenario, gasoline prices will increase by about $0.12 to $0.32 per gallon and diesel prices will increase by about $0.42 per gallon.
- We recommend that policymakers continue to provide flexibility in transportation GHG reduction strategies (especially for policies like LCFS designed to create market transformation) and consider any minor adjustments to the LCFS program rules if needed to maintain abatement from LCFS in the long term while minimizing adverse economic impacts in the near term.

4.4 Combined Heat and Power

4.4.1 Analysis and Key Assumptions

The combined heat and power (CHP) analysis estimates installation of new topping-cycle gas-fired CHP facilities between 2011 and 2020, given current market and policy drivers for CHP in California.[46] The rate of installation, the technology types of CHP installed and operational

[46] This analysis did not attempt to model installation of renewable fuel or bottoming-cycle CHP.

characteristics of these units are varied to create a range of plausible outcomes. GHG abatement from these installation portfolios and the unit abatement costs for each portfolio is then determined.

This analysis is built upon two CHP studies conducted for the California Energy Commission by ICF International.[47] Adjustments are made to ICF's assumptions, where appropriate, based on public sources to generate alternate California -wide scenarios. The E3 analysis consists of the following key steps:

Step 1: Categorize technical potential: Statewide technical (or theoretical) potential projections for capacity and load factor categories or "bins" are taken from *ICF 2012*. *ICF 2012* report estimates new CHP installations in existing and new facilities through 2029. These data are combined to provide technical potential estimates for each bin, for each year through 2020. A bin-based analysis is required because the methodology for estimating the key components of unit abatement cost (i.e., CHP installation costs, avoided costs and avoided emissions) depends on installation-specific attributes, such as technology, used thermal output and load factor of the installation.

Step 2: Estimate economic potential: The participant-based economic potential[48] is modeled for comparison to the projected installations in each scenario. Installations beyond what is cost-effective from a participant's perspective require subsidies.

Step 3: Estimate annual installed capacity: Adoption of CHP systems over time and 2020 annual installed capacity are estimated using two methods. The first method assumes that the rate of CHP installations varies over time based on an s-shaped adoption curve similar to the method used in the ICF reports.[49] The second method estimates future adoption based on historical adoption rates of CHP in the state and provides a comparison for s-curve-based installation rates. Two of the historic growth rates (PURPA and SGIP rates) were selected to provide a comparison to particular historic incentives regimes that helped drive CHP installation

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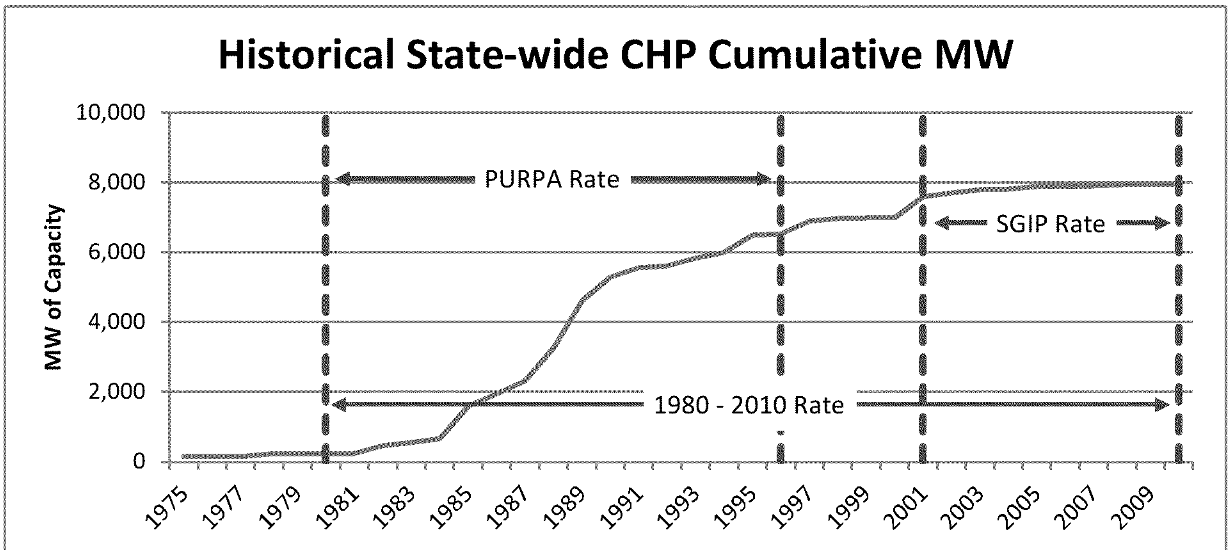
[47] These ICF studies (*ICF 2009* and *ICF 2012*) employ representative CHP technologies (in capacities ranging from 50kW to greater than 20MW), for installations with high and low load factors, includes some installations that export electricity, and includes installations with and without cooling applications in addition to installations with only heating applications.

[48] Economic Potential in the CHP analysis means the portion of the technical potential of CHP installations which are cost-effective from a participant perspective. As used here, participant-based economic potential differs from a typical interpretation of economic potential in that it includes hurdle rates for market barriers and participant risk premiums.

[49] A portion of participant based economic potential that is realized as installed CHP. Achievable potential is calculated based on CHP technical potential and factors in economics as well as real-world barriers to estimate adoption.

in California.[50] Figure CHP-1 shows state-wide historical installations along with time periods over which these benchmark rates were derived.

Figure CHP-2. Historical Cumulative California-wide CHP Capacity Installations



A mix of CHP technologies constructs a portfolio of installed CHP in the above mentioned scenarios. In the cases that employ the historic adoption rates, portfolios are constructed assuming that only the shortest payback technologies are installed for each modeled market segment. The portfolio technology mix of the s -curve adoption approach is based on empirical factors and assumes that some of the more expensive technologies are built.

Step 4: Estimate unit abatement cost: Given the estimated trajectory of annual installations for each technology across all bins, the two components of unit abatement cost are estimated over the lifecycle of the systems: net costs (i.e., CHP installation and operation costs minus avoided costs minus revenue from exports), and avoided GHG emissions. CHP operating costs include capital, fuel and operating and maintenance costs over the lifetime of the installation. Avoided costs are a result of avoided electricity purchases, and avoided gas and electricity costs

[50] The three benchmark historical adoption rates were derived by dividing the historical CHP installation statewide dataset into three different time periods over which the average annual installation is calculated. Two of these periods look at CHP installations in response to particular incentive regimes; the PURPA period looks at installations during the era of PURPA contracts between 1980 and 1996 and is roughly 390 MW/year while the SGIP period looks at installations during the SGIP incentive which is from 2001 until the end of the dataset in 2010 and is approximately 23 MW/year. The third rate simply takes the average between 1980 and the end of the dataset, looking at an average of about 260MW/year over that time span.

otherwise required to provide heating and cooling. Units that export power to the grid receive revenue from these sales. Avoided emissions include avoided boiler emissions, avoided electric emissions and in the case of chilling applications, additional avoided electric chiller emissions. CHP units also generate emissions on site, and these emissions are subtracted from avoided emissions to determine net avoided emissions.

The abatement cost for the portfolio of installations is calculated by dividi ng cost calculations by emissions reductions for the cumulative installations by 2020. For CHP, the C arbon Metric is highly sensitive to subtle changes in the model parameters , and complications can arise in the interpretation of Carbon Metric numbers from CHP installations that increase emissions. To address these challenges the cost of abatement for the entire portfolio is calculated, summing the costs and benefits from a Total resource cost perspective for all installations and dividing by total net emissions.

To further examine the emissions reduction findings this study represents abatement cost and total resource costs of the representative CHP technologies broken out by size and application.

4.4.2 Key Factors and Scenarios

Table CHP-1 shows the key factors identified and analyzed to determine a plausible range for abatement potential from CHP measures. A 'low cost' or 'optimistic case' and 'high cost' or 'pessimistic case' and assumptions are formulated to capture the uncertainty in the GHG abatement potential and abatement costs. Under the low cost assumptions, less mature CHP technologies decline in cost over time, are designed and operated to maximize capacity factors and thermal utilization, and exhibit no deterioration in heat rates. In the h igh cost case, costs for less mature CHP technologies do not decline with time, exhibit heat rate degradation, and may not be designed or operated to maximize thermal utilization, resulting in lower capacity factors and less-than-optimal matching of thermal output with on-site thermal load.

Table CHP-1: CHP Key Drivers for Greenhouse Gas Abatement Cost and Potential

Driver	Low Cost Scenario	High cost scenario
Learning rate	Fuel cells and microturbine learning derived from the Itron SGIP - DG cost-effectiveness report	No Learning
Hours of operation	ICF 2012 CHP report	80% of low cost scenario, rough estimate based on the SGIP 10th year impact evaluation
Thermal utilization	ICF 2012 CHP report	80% of low cost scenario, rough estimate based on the SGIP 10th year impact evaluation
Degradation in heat rate	No degradation	Itron SGIP - DG cost-effectiveness report
Avoided boiler efficiency	80%, based on ICF 2009 CHP Report and Itron cost-effectiveness report	85%, based on the ARB boiler efficiency assumption and consistent with a CEC boiler survey[51]

4.4.3 Initial Results

Figure CHP-2 shows the total installations for each year. Achievable potential estimates (using the s-curve growth rate) in 2020 are 630 MW and 1,500 MW for the high cost and low cost scenarios, respectively. Overlaying historical adoption rates result in a range from 394 MW for the SGIP adoption rate to 3,940 MW for the PURPA adoption rate. By examining the achievable potential estimates and the most recent historical adoption rate (SGIP), it seems unlikely that the original ARB Scoping Plan 4,000 MW capacity estimate for CHP will be met. Installation rate approximately matching the PURPA historical adoption rate would be required to meet the 4,000 MW CHP penetration estimate by 2020. However, the PURPA adoption rate implies that some installations would be uneconomic, and would need additional subsidies (beyond existing CHP programs) to be built.

[51] CARB assumes 85% efficiency for boilers in allowance allocation methodology, see page J-53 of *ARB 2010c*.

Figure CHP-2: CHP achievable potential through 2020 along with historical trend projections

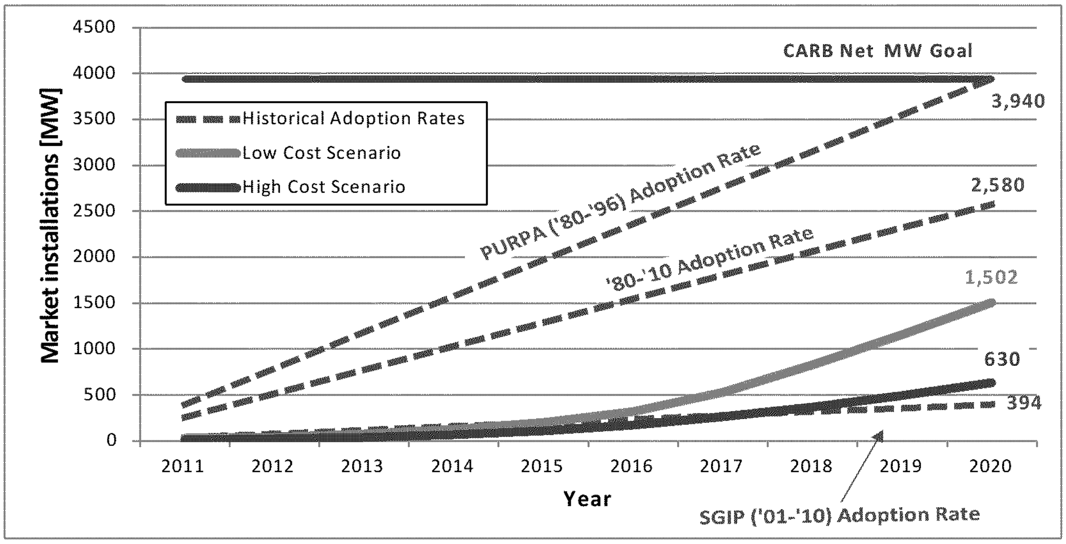


Figure CHP -3 shows estimate avoided emissions ranging from 0.13 -2.2 million metric tons CO_2e and 0.05-1.0 million metric tons CO_2e in 2020 for the low cost and high cost assumptions, respectively. The estimated CHP avoided emissions in all cases —even when installations are growing at the highest levels of historical adoption (PURPA rate)—fall considerably short of the 2008 Scoping Plan GHG emission abatement estimate of 6.7 million metric tons CO_2e.

Figure CHP-3: Emission reductions for achievable potential and historical adoption rates under low cost and high cost assumption

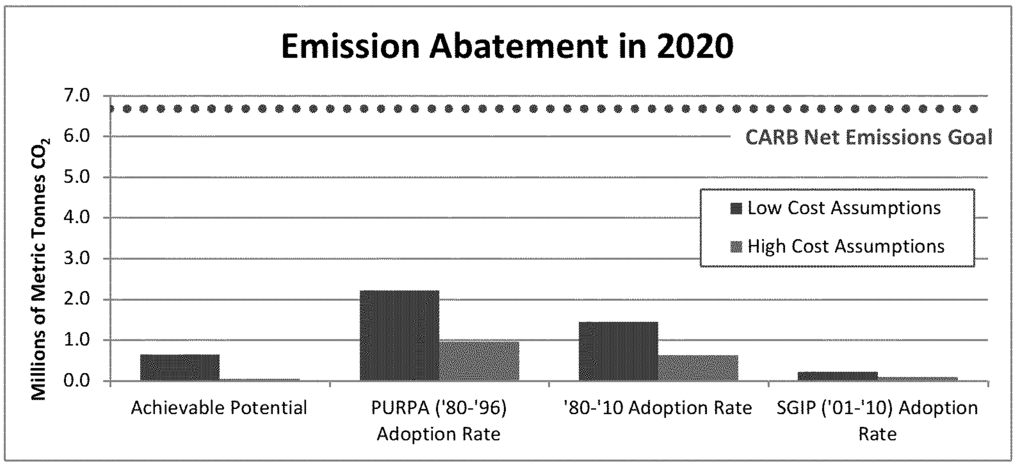


Table CHP-2 summarizes the abatement cost for the portfolio of installations. For the portfolios constructed using the s-curve adoption approach, the portfolio costs vary significantly and are

\$80/metric ton under low cost assumptions and -\$12,000/metric ton CO_2e under high cost assumptions. Note, the negative abatement cost under the pessimistic assumptions is a result of negative emissions reductions (emissions increases), rather than negative cost. For historical adoption rates, cost of abatement is \$7/ metric ton CO_2e under low cost assumptions and \$112/ metric ton CO_2e under high cost assumptions. [52] (The portfolio costs between the historical adoption rates and s-curve are not directly comparable because they are based on different technology adoption methodologies as described previously in section 4.1 Step 3.)

Table CHP-2: Cost of Abatement for the CHP Portfolio, Benefits, and Avoided emissions

Portfolio CO_2 metric components	Low cost assumptions	High cost assumptions
Portfolios based on SGIP historical adoption rate		
Lifecycle Costs [Millions 2010 Dollars]	2,289	1,871
Lifecycle Benefits [Millions 2010 Dollars]	2,277	1,800
Lifecycle Net Avoided Emissions [MMT CO_2e]	1.7	0.6
Cost of abatement [2010 dollars/metric ton CO_2e]	**7**	**112**
Portfolios based on S curve		
Lifecycle Costs [Millions 2010 Dollars]	7,900	2,380
Lifecycle Benefits [Millions 2010 Dollars]	7,580	1,890
Lifecycle Net Avoided Emissions [MMT CO_2e]	4.1	-0.04
Cost of abatement [2010 dollars/metric ton CO_2e]	**80**	**(12,000) (*)**

Values are taken from the model which carries more significant figures than are displayed here. There may be small differences due to the net cost/net emissions calculation and the reported CO_2 metric on account of this rounding.

* Note, the Carbon Metric is negative because the avoided emissions are *negative*, not because net costs are negative.

To further examine the emissions reduction findings, the abatement and total resource costs of the representative CHP technologies (broken out by size and application) under low and high

[52] The abatement costs on a \$/metric ton CO_2e basis is identical for all portfolios constructed using historical adoption rates, for a given cost scenario. This is because the mix of technologies does not change for the scenarios based on historical adoption rates.

cost assumptions were estimated. We find a wide range of emissions and cost performance across CHP technology type and a pplication. In the low cost scenario, larger systems across technology types generally reduce emissions and are relatively low cost. Smaller systems tend to be either high er cost (e.g., fuel cell) or emissions increasing (e.g., micro turbine) or both. Under the high cost assumptions, when assuming less efficient operation, even some larger systems are emissions increasing and fairly expensive. Under high cost assumptions, smaller systems that are high cost become more expensive and emissions increasing systems emit even more GHGs.

4.4.4 Takeaways

A key takeaway from this analysis is that new installations of topping-cycle CHP in California are unlikely to result in GHG emissions reductions as large as the ARB's 2008 Scoping Plan estimates. This result is robu st under both a low cost scenario (representing more optimistic operation) and a high cost scenario (representing less optimistic operation). As a result, we recommend that ARB revisit the 2008 Scoping Plan 2020 abatement estimate from CHP.

The GHG performance of the CHP systems examined depends on the characteristics of the specific site, facility type, and technolog y selected. We present a range of cost and emission savings and note that CHP system s can be net emitting if deployed and operated in a n inefficient manner. As a result, we conclude that ARB and the CEC should i mprove the public availability of greenhouse gas efficiency reporting data to increase transparency around what portion of the existing CHP fleet reduces GHGs.

We also note that policy support has historically played a key role in CHP development in California. Although the overall GHG abatement from topping-cycle CHP may be relatively small, well-constructed policies which incentivize CHP facilities to perform as -designed will b e necessary for CHP to maximize the potential for emission reductions and help reduce costs. Equally, we b elieve that policymakers should avoid unnecessary subsidies to mature technologies with limited long -term GHG abatement potential (e.g., conventional topping-cycle CHP). To implement this suggestion, policies should distinguish topping-cycle natural gas CHP from other forms of CHP (e.g., bottoming cycle, renewable-fired topping-cycle, etc.).

4.5 Offset Credits

4.5.1 Analysis and Key Assumptions

Offset project types included in the analysis are described in protocols developed under recognized offset standards bodies, including the C limate Action Reserve (CAR) and the American Carbon Registry (ACR). Table OC -1 lists the project types analyzed. Th ey include those approved for use by the ARB in meeting AB 32 compliance obligations, those under consideration by ARB, and those that could be approved by ARB in the future.

The analysis consists of two key components: (i) determining the unit abatement cost for each project type, derived from estimates of capital costs, operating costs and emissions abated, and

(ii) modeling the volume of offsets that could be generated from each project type. The cost and emissions assumptions for the project types are based on public information from sources such as the EPA, DOE, USDA and USFS. The volume of offsets available to the market is projected based on the expected timing of offset protocol adoption, timing of offset issuance from projects currently registered and listed in the CAR database , and an extrapolation of the expected volume from current and future projects.

Table OC-1: Project Types Included in the Carbon Metric Analysis

Category	Project Type
Approved by ARB	Forestry (Avoided Conversion, Improved Forest Management, Reforestation)
	Urban Forestry
	Ozone Depleting Substances (US Foam and Refrigerants)
	Livestock
Under Consideration by ARB	Coal Mine Methane (Ventilation Air Methane and Drainage)
	Rice Cultivation
Speculative*	Landfill Gas (for Electricity Generation, Direct Distribution, or Flaring)
	Landfill Gas (Small-Scale Landfills)
	Wastewater Treatment
	Organic Waste Composting
	Organic Waste Digestion
	Pneumatic Controllers
	Fertilizer Management
	Enteric Fermentation
	Nitric Acid Production (Secondary Catalyst)
	Nitric Acid Production (Tertiary Catalyst)

*Includes project types for which protocols have been developed but are not currently being considered for adoption by ARB

4.5.2 Key Factors and Scenarios

Key factors affecting unit abatement costs: These factors include protocols available for use under AB 32; market values of energy conserved; the value of forest and agricultural lands hosting offset projects; project capital costs; project maintenance costs; revenues from sales of co-products (e.g., electricity or biogas) and available offset volume from projects included in the analysis. Table OC -2 lists the key factors, the correlation with unit abatement cost, and the assumptions for the two scenarios: High Cost/Low Supply ("High Cost") and Low Cost/High Supply ("Low Cost").

Protocols: Compliance-eligible offset project types are defined by the early action and compliance offset protocols that have been formally adopted by ARB , which currently include Livestock, Ozone Depleting Substances, Urban Forestry, and US Forestry. ARB has begun the public process to evaluate and develop compliance offset protocols for Rice Cultivation and Coal Mine Methane; a technical workshop on these protocols was held in March 2013.

Additional protocols are expected to be added in the future. However, there is uncertainty about the volume of supply from future protocols because of requirements from the Western Climate Initiative (WCI). The WCI set a legal performance standard for all partner jurisdictions; if one partner jurisdiction has a regulation or law requiring an abatement activity, that activity cannot be considered as an offset in any other jurisdiction.[53] Potential new regulation in California further adds to this uncertainty.

Market value of energy units conserved: Unit abatement costs decrease with increases in prices for substances conserved as part of project activities. High prices for substances conserved, such as natural gas for pneumatic controller retrofits, result in increased cash inflows, and hence, lower project net costs. For forestry projects, abatement costs are driven by the value of the plots' alternative uses. For instance, if the plot's value for real estate or timber increases preserving these plots via offset projects becomes more costly.

Table OC-2: Key Factors for Unit Abatement Cost of Offsets

Key Factors for Unit Abatement Cost	Correlation with Unit Abatement Cost	High Cost Scenario	Low Cost Scenario
Protocols that are included	Varies based on specific protocol that is included/excluded	Exclude Landfill protocols	Include Landfill protocols
Abatement per physical unit such as a cow, a ton of municipal solid waste, etc.	Negative	Low abatement potential	High abatement potential
Offset volume	Negative	• Listing rate decreased by factor of 4 relative to recent rates • Revenues from offset sales: Low	• Listing rate increased by a factor of 3 relative to recent rates • Revenues from offset sales: High
Project costs: Capital, O&M	Positive	High	Low

Offset volume: The volume of offsets available to the market is primarily driven by the number and performance of projects developed under currently-approved protocols. Thus, the number

[53] See page 11 of *WCI 2010*

of protocols approved by the ARB, and the timing of approval are key factors. For an a pproved protocol, offset supply is affected adversely by factors that lower the expected income from offset sales, because this makes fewer projects financially viable. Factors that could lower expected income include stricter project requirements and offset invalidation rules.

Another key variable driving offset supply is the rate at which new projects are listed (the "listing rate"). The Low Cost s cenario increases the listing rate of new projects by a factor of three and the High Cost scenario decrease s the listing rate by a factor of four relative to recent rates. Listing rates can also be affected by the rate and volume of offset invalidation[54], therefore, the High Cost s cenario reduces the number of offsets awarded to all projects by 5% to account for this variable.

Project costs: Project capital and operating costs depend on project -specific factors such as technology, location, and operational efficiency; the plausible range for these values is reflected in the assumptions for the two scenarios.

4.5.3 Initial Results

Table OC-3 presents the results for offset supply and unit abatement costs under the High Cost and Low Cost scenarios. Table OC -4 summarizes whether the cap-and-trade regulation's Quantitative Usage Limit[55] for the three compliance periods can be met under the two scenarios.

[54] An offset can be invalidated up to three or eight years after it was issued if: (1) its verification report overstates offsets by more than 5%, (2) its project is not in accordance with all local, state, and national environmental, health and safety regulations during the reporting period, or (3) it was issued by another program for the same period.

[55] The cap-and-trade regulation's Quantitative Usage Limit restricts each compliance entity's use of offsets to up to 8% of its compliance obligation for each compliance period. Statewide, this translates to a maximum usable quantity of offsets that is 8% of the total GHG emissions covered by the cap for each compliance period. Compliance entities cannot "roll over" any unused amount of their limit to the next compliance period; the effect of this element of the regulation is not captured in these estimates.

Table OC-3: Cumulative Abatement and Unit Abatement Cost for Offsets (2013 – 2020) – Initial Estimates

Protocol Type	Plausible Low Cost		Plausible High Cost	
	2013-2020 Cumulative Abatement Potential (Million Metric Tons)	*Average Abatement Cost ($/Metric Ton)*	*2013-2020 Cumulative Abatement Potential (Million Metric Tons)*	*Average Abatement Cost ($/Metric Ton)*
Approved Protocols*	77	$17	68	$44
Under Consideration Protocols**	85	$21	75	$48
Speculative Protocols***	239	$15	202	$39

Estimates include offsets created between 2005-2012 that could be eligible for compliance.
* Forestry, Livestock, ODS, and Urban Forestry
** Coal Mine Methane and Rice Cultivation
*** Eight protocols that have been developed and could be considered for inclusion as compliance offset protocols by the ARB in the future.

+ Abatement potential compared to the total amount of allowable offsets permitted by the ARB cap-and-trade rule (218 MMT, cumulative from 2013-2020).

All $ values in constant 2010 dollars

Color Code	Abatement+	Abatement Costs
	Achieving program targets	Low Cost (<$14/MT)
	Slightly below program targets	Moderate Cost($14<x<$66)
	Significantly below program targets	High Cost (>$66/MT)

Table OC-3 shows a moderate difference in the supply of offsets between the two scenarios, but a substantial difference in the cost of generating offsets. The offset supply estimates are driven by the protocols included and number of projects coming on-line, not by the quantity of offsets per project. Abatement costs, on the other hand, range widely across the two scenarios due to the large range of costs in publicly-available data sets.

Table OC-4: Offset Supply relative to the 8% Quantitative Usage Limit

Protocol Category	Plausible Low Cost Scenario			Plausible High Cost Scenario		
	2013-2014	2015-2017	2018-2020	2013-2014	2015-2017	2018-2020
	Estimates include offsets created in 2005-2012 that could be eligible for compliance.					
Approved	Not Met	Not Met	Not Met	Not Met	Not Met	Not Met
+ Under Consideration	Not Met	Not Met	Not Met	Not Met	Not Met	Not Met
+ Speculative	Met	Met	Met	Met	Not Met	Not Met

Under both the high cost and low cost scenarios, offset protocols that are currently approved by ARB for compliance purposes do not meet the full Quantitative Usage Limit in any compliance period. The addition of protocols that are currently under consideration does not increase supply enough in either scenario to meet the Quantitative Usage Limit in any compliance period. The addition of speculative protocols generates enough supply to meet the Quantitative Usage Limit in only the first compliance period under the high cost scenario but not the second or third compliance periods. The full Quantitative Usage Limit is only met across eac h compliance period in the low cost scenario and when most of the speculative protocols analyzed in this report are compliance eligible.

The cost of achieving GHG reduction s through offset projects varies significantly based on assumptions for key cost fa ctors, and the actual project types included in the estimate. Thus lower unit abatement costs can be achieved if protocols with high abatement potential and/or lower project costs are approved.

Project transaction and financing costs for projects from approved protocols may be lowered by improving the regulatory infrastructure to create transparency and efficiency in the ARB issuance process, and by creating a robust market infrastructure to provide certainty and easier access to capital . These factors can also result in a greater number of projects listed. While these strategies can help lower both capital costs and transaction costs for projects, they are estimated to have a smaller impact than the approval of additional protocols.

4.5.4 Takeaways

Offset supply is most directly affected by the number and type of approved protocols. For approved protocols, supply may be increased by facilitating the process for Early Action Offset Credits to be issued as ARB Offset Credits. Providing early notice about wh ich and when new protocols will be approved would also help to promote the market readiness necessary to deliver the volumes of supply needed for compliance. In addition, lower unit abatement costs can be achieved if protocols with high abatement potential and/or lower project costs are approved. Expansion of the geographic applicability of offset protocols would also increase offset supply. However, the timely approval of additional protocols will do the most to help to deliver the volumes of supply needed for compliance. Therefore, we recommend that ARB adopt additional offset protocols to enhance the effectiveness of offsets as a cost-containment tool, and support development of sector-based offset programs (e.g., Brazilian REDD).

4.6 Conclusions from Analysis of Existing Measures

In this section, we: (1) summarize unit cost and abatement potential estimates across abatement measures, (2) highlight key conclusions and takeaways from comparisons across measures.

4.6.1 Summary of unit cost and abatement potential

Table C-1 below summarizes, for all program measures analyzed, the average unit abatement cost and the 2020 abatement potential.

Table C-1: Summary of Unit Abatement Costs and Abatement Potential

Program Measure	Plausible Low Cost		Plausible High Cost	
	2020 Abatement (Million Metric Tons)	*Average Abatement Cost ($/Metric Ton)*	*2020 Abatement (Million Metric Tons)*	*Average Abatement Cost ($/Metric Ton)*
Low Carbon Fuel Standard*	16.3	$94	14.9	$182
Renewables	12.9	$149	12.9	$201
Energy Efficiency (Electric)	12.5	($114)	9.4	($101)
Energy Efficiency (Natural Gas)	1.6	($108)	1.6	($79)
Combined Heat and Power**	0.6	$7	0.05	$112

* LCFS values reported on a well-to-wheel basis

** Analysis was limited to topping-cycle CHP and did not consider renewable or bottoming-cycle CHP

All $ values in constant 2010 dollars

Color Code	Abatement	Abatement Costs
	Achieving program targets	Low Cost (<$14/MT)
	Slightly below program targets	Moderate Cost($14<x<$66)
	Significantly below program targets	High Cost (>$66/MT)

2020 Abatement Observations

Major drivers of abatement include RPS, LCFS, and Electric EE. CHP and Natural Gas EE offer more modest contributions. If several additional offset protocols are approved, offset credits can provide significant abatement. The magnitudes of 2020 abatement estimates from EE, RPS and the LCFS are generally consistent with the most current estimates published by ARB. Our analysis predicts 2020 abatement from CHP to be significantly below the most recent ARB estimate and identifies some possible challenges in achieving the LCFS program abatement targets under the more pessimistic scenario.

Abatement Cost Observations

We observe a wide range in the cost -effectiveness of the major Scoping Plan measures, from energy efficiency measures that save Californians on the order of one hundred dollars per ton reduced, to RPS and LCFS activities that cost as much as two hundred dollars per metric ton. In general, the ordinal rankings of the measures' cost-effectiveness remain consistent between the high and the low cost scenarios but the magnitude of each measure's $/metric ton value changes significantly between scenarios.

Taking a narrow view, a least-cost response would entail maximizing low cost options, such as energy efficiency, prior to expanding implementation of expensive measures such as RPS or the LCFS. A broader view of cost-effectiveness looks beyond prioritizing only on what is least cost today, and recognizes that some amount of high cost activities today may be needed to drive innovation and diffusion of clean technologies required to achieve long-term carbon reduction goals.

4.6.2 Impact of regulatory requirements on cost-effectiveness

Because many emissions reducing activities occur as a result of regulatory mandates, the sequence in which these activities are undertaken is not strictly based on economic considerations. For instance, entities may focus on renewables procurement to comply with RPS requirement, even if other alternatives could yield similar reductions at lower costs. In addition, some more cost-effective emission reducing activities may not occur because the current regulatory framework does not enable these activities or because the market in these areas is unlikely to develop in the time frame required by the regulation. Even within a given regulatory measure abatement might not move smoothly up a theoretical cost-curve. This is clearly observed in the LCFS and RPS studies.

4.6.3 Non cost-effectiveness related observations

Conducting this deep-dive analysis of existing Scoping Plan measures provided insights beyond the cost-effectiveness and 2020 abatement results. Table C-2 lists key recommendations by measure analyzed that were derived from this work.

Table C-2: Key Recommendations from Carbon Metric Analysis of Existing Scoping Plan Measures

Measure	Recommendations
Energy Efficiency	➢ Continue to support and improve upon utility-run efficiency programs ➢ Deploy additional funds from proposition 39, cap-and-trade revenue and other funding sources efficiently ➢ Support continued improvement in compliance with codes and standards ➢ Scale up efforts to quantify water system energy efficiency potential and target these savings through coordinated stakeholder efforts
Renewable Portfolio Standard	➢ Improve understanding of delivered RPS costs including technology cost declines, integration costs and transmission costs ➢ Support more affordable design of any future RPS
Combined Heat and Power	➢ Structure and target incentives to support CHP technologies that have long term abatement potential (e.g., renewable and bottoming-cycle) ➢ Avoid unnecessary subsidies to mature technologies with limited long-term abatement potential (e.g., conventional topping-cycle CHP) ➢ Revisit the 2008 Scoping Plan 2020 abatement estimate from CHP ➢ When estimating GHG abatement, distinguish topping-cycle natural gas CHP from bottoming-cycle and renewable CHP ➢ Improve greenhouse gas efficiency reporting to identify when CHP reduces GHGs
Low Carbon Fuel Standard	➢ Continue to provide flexibility in transportation GHG reduction strategies, especially for policies designed to create market transformation ➢ Consider adjusting the LCFS program rules if needed to maintain abatement from LCFS in the long term, and minimize adverse economic impacts in the near term
Offsets	➢ Adopt additional offset protocols to enhance the effectiveness of offsets as a cost-containment tool ➢ Support development of sector-based offset programs (e.g., Brazilian REDD)

5 Next Steps – Proposed Future Use of the Carbon Metric

The Carbon Metric analysis described in this report demonstrates the usefulness of the analytical framework. To facilitate ongoing discussion, publicly available information has been used, and the analysis is positioned for public review and comment, with assumptions clearly stated and limitations acknowledged. The scenario approach, providing a range for resulting estimates, allows the discussion to focus on opportunities to lower costs and/or increase abatement potential.

This section discusses potential venues for use of this framework and describes how the metric could be coupled with carbon prices from the cap-and-trade program to implement a cost-effectiveness screen as required by AB 32.

5.1.1 Venues for Potential Use of the Carbon Metric

The Carbon Metric framework could usefully inform the following policy areas:

- ***AB 32 Scoping Plan:*** The central planning document outlining ways to implement the AB 32 goal is the California Air Resources Board Scoping Plan. [56] The 2008 Scoping Plan proposes a broad approach to GHG reductions that is comprised of a set of targeted program measures and an overarching cap-and-trade system. By statute, the Scoping Plan must be updated every five years. ARB is currently undertaking the first of these quinquennial updates.
- ***Auction Proceeds Investment Plan:*** The ARB's cap-and-trade program will create auction proceeds that must be expended by the state to reduce greenhouse gases. In 2012, the Legislature passed and Governor Brown signed into law three related bills — AB 1532 (Pérez, Chapter 807), SB 535 (De León, Chapter 830), and SB 1018 (Budget and Fiscal Review Committee, Chapter 39). These pieces of legislation require that the Department of Finance submit a plan to the Legislature that identifies priority investments that will help achieve GHG reduction goals. Funding will be appropriated to State agencies by the Legislature after receiving input from the Administration through its three-year investment plan. While developing this investment plan, the Department of Finance coordinates with the ARB and other State agencies. In May of 2013 the Department of Finance and ARB released an investment plan [57] *The document contained no formal method of prioritizing investment addressing the cost-effectiveness requirements of AB 32.*
- ***Proposition 39 Investment:*** In November 2012, California voters passes a ballot initiative known as Proposition 39 (Prop 39) that increased income tax on multi-state businesses and earmarked a portion of the increased tax revenues for energy efficiency projects. Expending these funds efficiently could potentially create significant synergies with other efforts to reduce GHGs and achieve AB 32 targets.
- ***Post-2020 GHG reduction policy:*** Policymakers are beginning to consider the need for additional California GHG reduction policy after the 2020 timeframe. The Carbon Metric is well suited to inform such deliberations.

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[56] *ARB 2008a*

[57] *ARB 2013*

5.1.2 Applying Cost-Effectiveness Screens to AB 32 Actions Using the Carbon Metric and the Cap-and-Trade Carbon Price Band

Under perfect market conditions, carbon pricing is the first-best solution to create a least-cost policy framework to reduce GHGs. Policymakers select either a carbon tax or a cap-and-trade system to create the carbon price. In response to this price signal, covered entities take abatement action if it makes economic sense to do so. Therefore, actions taken under such a pricing regime are inherently cost-effective from the perspective of the entities that observe this price.[58] Carbon pricing can be supplemented by negative cost policies designed to remove investment barriers and technology advancement policies (often high cost) designed to facilitate innovation and reduce the costs of long-term carbon reduction. These three conceptual categories are represented pictorially in Figure NS-1.

Figure NS-1. Conceptual Representation of GHG Reduction Framework that Includes a Carbon Price, Energy Efficiency and Technology Advancement Policies

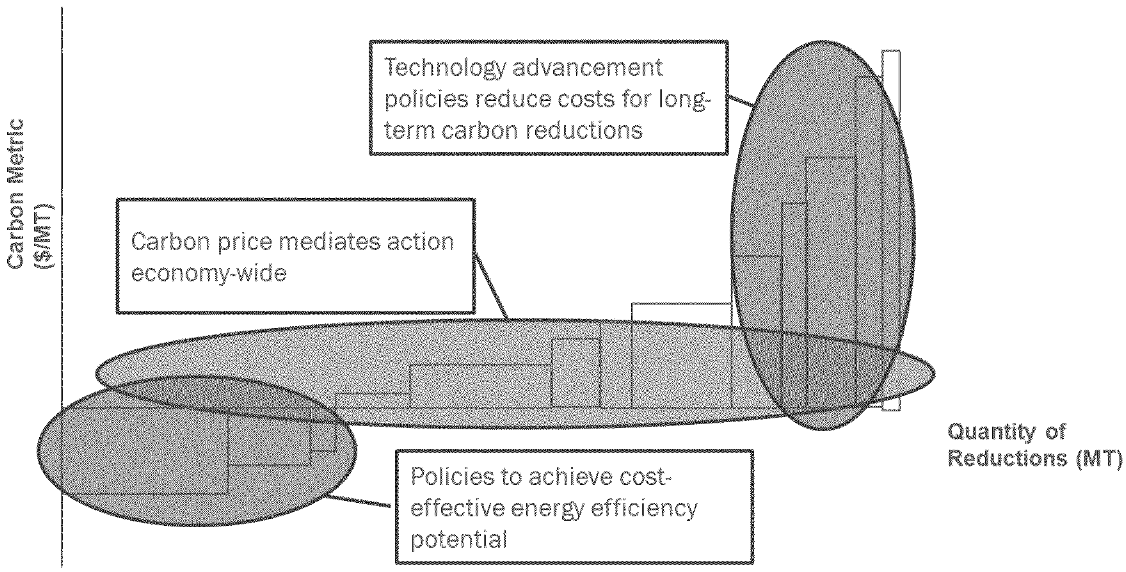

Figure Adapted from: **IEA 2011a**

All three of these policy categories exist in the California GHG reduction framework. The ARB's cap-and-trade program provides a transparent band of expected carbon prices between now and 2020. This price band is implemented through the use of a price floor known as the "Auction Floor Price" and a soft price ceiling known as the "Allowance Price Containment

[58] Cost-effectiveness for the participant taking the action is independent of cost-effectiveness as defined under the TRC or SCT. However, many measures that are cost effective to an individual participant are also cost-effective to society under the other tests.

Reserve".[59] The carbon price band administratively chosen by ARB provides a good indication of ARB's perception of California's "willingness to pay" for GHG reductions.

On one end of the cost curve, California has a long history of successful energy efficiency policies. As discussed in Section 4.1, current EE policies primarily target areas of negative-cost emission reduction opportunities—actions that save California money but are not taken due to market barriers.[60] Carbon pricing may make already cost-effective EE even more attractive but is unlikely to remove all barriers.[61]

On the other end of the curve, California policymakers have also supported technology-forcing policies, such as the RPS and LCFS, designed to encourage innovation and diffusion of clean technologies. A limited amount of policies designed to drive scale-up of promising new technologies that are currently expensive may be justified using the argument that near-term support may reduce long-term costs.[62] Technology support of this type should be limited, as successfully picking winners is a challenging task.[63] Special treatment should be ramped down and removed once costs for deployment of the new technology come down significantly (the technology succeeds) or the new technology is deemed infeasible or remains very high cost (the technology fails). Any technology-forcing policy of this type should be constructed as broadly as possible to achieve GHG reductions (e.g., support for all low carbon fuels through LCFS is preferable to support for one specific low carbon fuel) and should be required to demonstrate, through additional analysis, that societal benefits outweigh societal costs to California.

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[59] The floor price begins at $10/metric ton for 2013 vintage allowances sold in 2012 and escalates at five percent per year plus the rate of inflation as measured by the consumer price index (§ 95911(c) of the cap-and-trade regulation). We approximate this value as $14/metric ton CO_2e in 2010 real dollars. The ceiling price begins at $50/metric ton CO_2e for 2013 vintage allowances sold in 2012 and escalates at five percent per year plus the rate of inflation. We approximate this value as $66/metric ton CO_2e in 2010 real dollars. Assuming 2% inflation, we estimate that the floor would be $17/metric ton CO_2e (in 2020 nominal dollars) and the ceiling would be $80/metric ton.

[60] EE barriers have been extensively studied and categorized. A few examples include imperfect information, principal-agent relationships and split incentives. For more information see *Jaffe 1994.*

[61] For a discussion of the interaction between EE policy and carbon pricing see *IEA 2011b*.

[62] For more details on this argument, see *IEA 2011a*.

[63] We recognize the gap between research, development and demonstration (RD&D) and full commercialization of new technologies. Although we are supportive of a limited amount of policies to drive a significant scale-up of technology deployment for promising new technologies (which are currently expensive), this type of activity should be limited and progress closely monitored.

With respect to high-cost measures ultimately justified using the secondary societal cost screen, we believe that decision makers should explore funding the "above -market" portion of program measure costs using sources other than utility customer rates. The benefits that make such measures cost-effective under the societal cost test do not accrue to utility ratepayers directly, but rather to society as a whole.

Building on the concepts described above, the Carbon M etric and the carbon price band from the ARB's cap -and-trade program could be used to sort abatement action proposals into 3 groups as shown in Table NS-1. Adoption of such a decision-making framework will —if well-practiced—result in cost-effective implementation of AB 32.

Table NS-1: Use of the Carbon Metric and Cap-and-Trade Carbon Price Band to Prioritize Implementation of AB 32 Actions

If The Carbon Metric is:	Cost-effectiveness Category	Proposed Action
1. Less than the 2020 Auction Price Floor (~$14/metric ton CO_2e*)	Always cost-effective	➢ Prioritize implementation ➢ Unlock abatement potential otherwise untapped by the carbon price signal ➢ Identify and address any barriers to adoption
2. Between the Auction Price Floor and the top price of the Allowance Price Containment Reserve (APCR)	May be cost-effective today, depending on carbon price	➢ Should be prioritized after measures in Group 1 ➢ Explore likelihood of cap-and-trade price signal driving reductions in this category
3. Above the top of the APCR (~$66/metric ton CO_2e*)	Unlikely to be cost-effective under expected near-term carbon prices	➢ Ensure actions are focused on achieving market transformation and reducing costs for long-term carbon reductions ➢ Evaluate if societal benefits outweigh societal costs ➢ Devote extra efforts to cost reduction ➢ Employ funding sources other than utility customer rates
* Carbon prices in this table are in 2010 dollars.		

In summary, the Carbon M etric analytical framework could serve as a template for prioritizing efforts in a variety of AB 32 proceedings. In this way, the merits of various market -based and program-based initiatives can be directly compared, and the state is well -positioned to embark upon a cost-efficient long-term GHG reduction path.

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7 Appendix: Additional Background on Cost-effectiveness Evaluation in the Utility Regulatory Context

Cost-effectiveness evaluation for distributed energy resources (DERs) has a long history in utility regulation in the United States, dating back to the 1970s when energy efficiency programs were first developed. DERs include energy efficiency, demand response, permanent load shifting (such as thermal storage systems) and distributed generation. Cost-effectiveness evaluation occurs at different stages in the program lifecycle of DERs. In the energy efficiency context, regulated utilities are typically required to submit cost-effectiveness evaluation of their proposed energy efficiency programs for budget approvals. Cost-effectiveness evaluation also occurs when utilities develop energy efficiency potential estimates, which are used to inform utility energy efficiency program goals.

In California, cost-effectiveness evaluation for DERs is described in the California Standard Practice Manual for the Economic Analysis of Demand-Side Programs and Projects issued by the CPUC and CEC.[64] There are five main cost-effectiveness tests in this manual. These are described in Table I-1 below.

Table I-1. Cost-Effectiveness Tests

Cost Test	Acronym	Purpose
Total Resource Cost Test	TRC	Financial impact from a societal level. Used to determine whether the program should be offered. In-state incentive levels do not change the TRC result.
Ratepayer Impact Measure	RIM	Impact on non-participating ratepayers. Used to balance the incentives so that other ratepayers are not disproportionately impacted by the program.
Program Administer Cost	PAC	Impact on ratepayers overall. Used to estimate the total costs of the program net of system benefits.
Participant Cost Test	PCT	Financial proposition to the customer. Used to define incentive and shows relative attractiveness of the program and estimating participation.
Societal Cost Test	SCT	Similar to the TRC however non-monetized benefits and costs are included, such as the health benefits from reduced criteria pollutant emissions.

The TRC is the primary test used to evaluate the overall cost-effectiveness of DERs in California (and many other jurisdictions). It measures the net benefits to the region as a whole, irrespective of who bears the costs and receives the benefits. Unlike the ratepayer, program

[64] Commonly referred to as the Standard Practice Manual (CPUC 2001). The National Action Plan for Energy Efficiency (E3 2008) also provides an excellent description of cost-effectiveness evaluation as it is applied towards energy efficiency program planning.

administrator, and participant test, the TRC does not take the view of any particular stakeholder. The incremental costs of purchasing and installing the DER system above the cost of standard equipment that would otherwise be insta lled, and the overhead costs of running the DER program are considered. The avoided costs are the benefits. Bill savings and in -state incentive payments are not included, as they are transfer payments between jurisdictional entities ('benefits' to customers and 'costs' to the utility that cancel each other on a regional level).

The TRC does not evaluate distributional impacts among stakeholders. Three other distributional tests evaluate the net benefits to different stakeholders. These additional stakeholder perspectives include non -participating ratepayers (RIM), the utility or program administrator (PAC) and the participant (PCT) perspectives.

The Participant Cost Test (PCT), for example, examines the costs and benefits from the perspective of the customer installing the DER system. Costs include the incremental costs of purchasing and installing the DER system above the cost of standard equipment that would otherwise be purchased by the customer. The benefits include customer bill savings, incent ives and any applicable government tax credits or incentives.

All remaining cost tests, with the exception of the SCT, can be calculated using the inputs for the PCT test and TRC test. [65] The table below lists the cost and benefit components of each test. For the SCT test, the non-monetized benefits must also be included.

Table I-2. Costs and Benefits Included in Each Cost-effectiveness Test

Component	TRC	SCT	RIM	PAC	PCT
Avoided Cost Benefits	Benefit	Benefit	Benefit	Benefit	-
Equipment and install costs	Cost	Cost	-	-	Cost
Program overhead costs	Cost	Cost	Cost	Cost	-
Incentive payments	-		Cost	Cost	Benefit
Bill Savings	-		Cost	-	Benefit
Non Monetized Benefits		Benefit			
Non Monetized Costs		Cost			

[65] The SCT, which is a variant of the TRC, has long been included in the Standard Practice Manual, but in has never been applied in a CPUC proceeding. The primary differences are consideration of additional non-monetized costs and benefits and use of a lower discount rate. See *CPUC 2013*.