Questions, Answers and Clarifications
Hydrogen Fuel Infrastructure Solicitation
PON-12-606
Alternative and Renewable Fuel and Vehicle Technology Program
California Energy Commission

Application Due Date

Q.1 Can the Application due date change be extended? (pages 5-8)
A.1 Yes. In accordance with Addendum #2, the application due date is now January 24, 2013 by 3:00pm.

Eligible Costs/Funding Information

Q.2 How are project costs defined?
A.2 Project costs are defined as all allowable, allocable and reasonable costs incurred pertaining to the implementation of the project's scope of work. For more details, see Section III.E (Eligible Costs) and Attachment 12 (Terms and Conditions).

Q.3 Over what timeframe are eligible costs allowable?
A.3 Expenses reimbursed by the Energy Commission must be incurred during the approved term of the executed Agreement. Match share expenditures are allowable from the date of the Notice of Proposed Award through the approved end term of the executed Agreement. Although Applications are required to demonstrate stations are constructed and operating by October 30, 2014, Agreement terms can be written through March 31, 2017 to allow for expenditures that occur during station operations (such as allowable Operations and Maintenance (O&M) costs, data collection costs, and reporting costs).

Q.4 What is the maximum funding cap per applicant?
A.4 Although unlikely, theoretically a single Applicant could receive up to $12.936 million under this solicitation while adhering to the Single Applicant Cap and being awarded all of the Non-Road Set Aside funds.

Q.5 Does a sliding scale exist for the project cost and the maximum award amount?
A.5 No. The maximum award amount is $1.5 million per station or 65% of total project costs, whichever is less. ***Exception:*** For projects awarded funding under the Renewable Set-Aside, the maximum award amount is $3.0 million per station or 65% of total project costs, whichever is less. A sliding scale will not be utilized under this solicitation.

Q.6 Do incentives exist for an Applicant to work on applications for multiple hydrogen fueling stations?
A.6 No.

Q.7 Can the 65% Energy Commission share be increased to 75%?
A.7 No.

Q.8 Is overhead and indirect an allowable cost?
A.8 Yes, as long as those costs are reasonable, documented, allowable and allocable to the approved project.

Q.9 Please clarify the reimbursement for insurance costs as an allowable Operations and Maintenance cost under Section III.F, pgs. 14-15. Does the bulleted list under item #2 (bottom of pg. 14) indicate minimum insurance requirements that must be in place to be eligible for reimbursement?
A.9 No. The bulleted list under item #2 (bottom of pg. 14) indicates the types of insurance that are ***not*** eligible as an allowable cost under a resulting funding agreement, neither as a reimbursable nor match share expenditure. Funding recipients will be required to document the allowability of all reimbursed or match share costs and demonstrate these costs meet the requirements of the funding agreement and funding solicitation.

Q.10 Can the Energy Commission make all SAE standards available to all applicants or reimburse applicants for the cost to procure these standards?
A.10 No. SAE standards are available for purchase from the SAE. As stated in the solicitation, costs incurred for application development or incurred prior to the execution of a funding agreement cannot be reimbursed. In addition, costs incurred prior to the Notice of Proposed Award cannot be counted towards match share towards the project.

Q.11 Can the solicitation be modified so it does not require references to the SAE standards in the technical proposal and allow standards to be purchased upon award or after release of the NOPA?
A.11 No. Applications must demonstrate the ability to comply with the required technical standards contained in the solicitation to facilitate evaluation of each proposal and to ensure high quality proposed projects.

Q.12 Can the "Accelerated Project Incentive" from previous hydrogen solicitation be reinstated?
A.12 No. The solicitation requires that applications demonstrate all proposed projects are constructed and operational by October 30, 2014. There are no accelerated project completion incentives in this solicitation.

Budget Forms

Q.13 Page 8 of Attachment 12 (Terms and Conditions) requires that subcontractor budget data must be submitted to the Commission Agreement Manager before any subcontractor costs can be incurred. Does this mean subcontractor detailed cost breakdowns requested in Attachment 5.B-4a need not be submitted with the proposal? If this detailed cost data is to be submitted, it implies the Applicant must select the subcontractor prior to grant award which does not typically allow for competitive bidding.
A.13 If known prior to submitting an Application, Applicants should provide detailed subcontractor cost breakdowns in Attachment 5.B-4a. If subcontractor(s) are not yet selected and/or detailed cost breakdowns are not yet available, Applicant should indicate that subcontractor(s) are “to be determined” and estimate subcontractor costs.

Grant Terms and Conditions

Q.14 Attachment 12 (Terms and Conditions) requires the Recipient to obtain Commission Agreement Manager approval prior to encumbering equipment acquired by the Recipient with grant funds. Can this requirement be removed?

A.14 No. However, the requirement to obtain Commission Agreement Manager approval to encumber the equipment only lasts for the duration of the funding agreement. Energy Commission continues to analyze options associated with equipment disposition under funding agreements. While the equipment disposition instructions and requirements under this solicitation will not be changed, these comments have been noted and will be utilized to inform future Energy Commission decisions on this topic.

Q.15 What is the term of operation?

A.15 At a minimum, stations must be operational through the end term date of the funding agreement which is expected to be March 31, 2017. As a reminder, stations are expected to be constructed, operational, and open to the public by October 30, 2014. While there is no specified operational terms beyond the Agreement end term date, actual station operation is expected to significantly exceed the end term date of the funding agreement. Applications demonstrating an ability to operate the proposed station for longer periods of time will score higher under the Market Viability scoring criterion.

Q.16 Can data be collected throughout the entire station operation, exceeding 12 months?

A.16 Data collection is required for a ***minimum*** of 12 months. The Energy Commission encourages data collection for longer than 12 months in order to improve understanding of station performance and utilization.

Single Applicant Cap

Q.17 If two different Applicants submit two different applications and collaborate with each other in the applications (i.e., as fully disclosed partners), how does the 40% Single Applicant Cap apply?

A.17 The 40% Single Applicant Cap (Section II.B, pg. 8) is applied to the entity submitting the Application and signing the Application Form (Attachment 1). Only one entity can be the applicant in an application.

Eligibility

Q.18 What is meant by the required project team experience: "the Applicant's key personnel, as identified in the scope of work, must each have a minimum of 3 years of experience designing, planning, constructing, testing, operating, or maintaining gaseous fueling stations"?

A.18 Key personnel are required to have at least ***one*** of these types of experience (see Section III.A, pg. 10). Applicants with team members whose expertise covers more technical, management, and project experience (for the types of experience listed) should identify and describe such experience and skill sets in the application so they could potentially score higher under the "Qualifications of the Applicant/Project Team" (see Section XII, Scoring Criteria).

Q.19 How should Applicants comply with CSA HGV 4.3: 2012?
A.19 Applicants are advised to describe their intent and plan for complying with CSA HGV 4.3 in their application(s). Applicants should describe their intent and plans to cooperate with the deployment of mobile devices in late 2013 for testing compliance with CSA HGV 4.3: 2012.

Q.20 Is dual pressure (Type A and Type B) a technical requirement for station operation and is dual pressure also required for peak capacity (five 7-kg fills in one hour)?
A.20 Yes. Dual pressure is a technical requirement of hydrogen fueling operations (Section III.C.5) and peak fueling capacity (Section III.C.4). The station must be capable of dispensing Type A and Type B for both station operation and peak capacity, although not necessarily simultaneously.

Q.21 Will station upgrades be funded?
A.21 Station upgrades are eligible for funding if they are located in an identified Station Location Area and otherwise are eligible projects as described in Section III.B.

Station Location Areas

Q.22 Can the Station Location Areas be changed?
A.22 No.

Q.23 The Existing and Recently Funded Hydrogen Fueling Stations contained in Table 2 (pg. 17) are primarily fleet or school stations, not valid commercial stations. Can the Station Location Areas be modified to allow commercial stations to be constructed in these areas under this solicitation?
A.23 No. The 25 Station Location Areas identified in the solicitation will remain unchanged. However, only stations competing for Non-Road Set-Aside funds may be located outside the Station Location Areas. The Energy Commission is aware that not all existing and planned hydrogen fueling stations are fully commercial yet and/or have full public access. However, planned stations funded under PON-09-608 and stations resulting from this solicitation (PON-12-606) are expected to develop the existing and planned station network to a network of commercial hydrogen stations providing unrestricted public access.

Q.24 There appears to be one or more Station Location Areas that do not contain an existing fueling station which is a requirement of the solicitation. How is an applicant expected to propose a valid project in these locations?
A.24 Energy Commission staff analysis has confirmed that all Station Location Areas contain multiple existing fueling stations. This comment was also received in response to the September 7, 2012 draft solicitation. The final Station Location Areas identified in this funding solicitation incorporates a significant expansion on the geographic areas contained in the draft solicitation specifically to increase the number of potential fueling station sites within each area.

Q.25 Why are non-road applications excluded from the Station Location Areas?
A.25 Non-road applications are ***not*** excluded from the Station Location Areas. Proposed stations co-located with an existing non-road fueling station within a Station Location Area can compete for funding as part of the prime competition. However, these stations are ***not eligible*** to compete for the Non-Road Set-Aside funds.

Q.26 Can the solicitation prioritize funding for the 12 Station Location Areas contained in the September 7, 2012 draft solicitation?
A.26 No. There are no priorities among the 25 Station Location Areas in the solicitation.

Q.27 Can an eligible project be outside the Station Location Areas?
A.27 Yes, only for eligible projects competing for Non-Road Set-Aside funds. Projects ***not*** competing for Non-Road Set-Aside funds ***must*** be located within the Station Location Areas identified in Table 2.

Q.28 Will there be another solicitation in the future that covers additional station location areas?
A.28 Although a future solicitation is anticipated, the detailed requirements of future solicitations remain undecided.

Q.29 Does STREET consider existing retail gasoline stations?
A.29 Yes.

Q.30 What is included in the mathematical computation for the Station Location Areas?
A.30 The Station Location Areas mathematically generated by STREET include:
- Population density per census tract
- Total vehicles per household
- Median household income
- Gasoline station locations
- Geographic proximity to freeways and interstates
- Vehicle ownership rate
- Land use
- Vehicle travel density

Application Requirements

Q.31 Can the requirement to submit one application per station be changed to allow one application for multiple stations?
A.31 No. To facilitate evaluation, scoring and selection of applications, the Energy Commission requires all applications to be separate, complete, and distinct for each proposed station submitted under the solicitation.

Q.32 For multiple stations, are individual applications required?
A.32 Yes.

Q.33 Who will supply demand numbers for the Project Plan which shows cash projection (page 27, item 10)?
A.33 Contrary to the verbal answer provided at the Pre-Application workshop, the Applicant is required to supply the demand numbers and their assumptions. Applicants are encouraged to submit a project plan which shows cash flow projection over the duration of the Energy Commission project. The Applicant shall describe all assumptions in their project plan so the reader of the project plan understands how cash-flow projections are derived.

Non-Road Set-Aside

Q.34 For the non-road set-aside, how much funding is available?
A.34 $1,500,000.

Q.35 For Non-Road Set Aside applications, are "existing" sources limited to fueling applications?
A.35 Yes.

Q.36 For Non-Road Set Aside applications, do existing sources include already planned stations?
A.36 No.

Q.37 For Non-Road Set Aside applications, is a mobile fueler considered to be existing hydrogen station?
A.37 No.

Q.38 Is an eligible non-road project one that already exists where hydrogen is not used for transportation?
A.38 In accordance with Section III.B, Applicants must document that the proposed station is located at an existing retail fueling station or co-located with an existing non-road hydrogen fueling station.

Renewable Hydrogen

Q.39 Can projects for 100% renewable hydrogen fueling stations apply for all funding under this solicitation?
A.39 Yes.

Q.40 Can the 40% Single Applicant Cap be changed to a preference for Renewable Hydrogen projects?
A.40 No. The Single Applicant Cap is established to provide market diversity and will remain unchanged. The solicitation, as written, currently provides a preference for Renewable Hydrogen projects as follows:

1) Establishment of the Renewable Hydrogen Set-Aside where only 100% renewable hydrogen projects are eligible to compete.
2) Renewable hydrogen applications not funded under the Renewable Hydrogen Set-Aside will compete for funding under the prime competition based on the project's merits.
3) Proposed projects exceeding the minimum 33% renewable hydrogen requirement will be scored higher under the Innovation scoring criterion and potentially under the Sustainability scoring criterion.
4) In the event of tied scores for two or more applications, the project containing a greater percentage of renewable hydrogen will be recommended for award.

Q.41 Can the Renewable Hydrogen Set-Aside be modified for an overall preference for 100% renewable hydrogen projects? If not enough 100% renewable hydrogen projects are proposed, the remaining applications can be funded.
A.41 100% renewable hydrogen stations are already preferred under this solicitation as explained under Question #9 above.

Q.42 Can the "Renewable Hydrogen Content" from the previous hydrogen solicitation be reinstated?

A.42 No. The solicitation already prefers 100% renewable hydrogen stations as detailed in Question #9 above.

Q.43 Section 8 states that only “Small hydroelectric (30 megawatts or less)” is considered a renewable electricity source. However, if hydro-electricity exceeding 30 MW comes from a large pre-existing lake (i.e., the power generation did not result in any change in the original lake dimensions), then shouldn’t this also qualify as a renewable electricity source?

A.43 No, this does not meet the California Renewable Portfolio Standard (RPS) standards.

Q.44 If biogas is generated in Sacramento and used in LA, is this a viable pathway to meet the renewable hydrogen requirements in the solicitation?

A.44 While this is not a fuel pathway defined in the Low Carbon Fuel Standard (LCFS) look up table, it is an acceptable physical pathway for describing how biogas may be transported to a hydrogen production facility for the purposes of this solicitation. The geographical transfer from one location to another is only one component of a well to wheel description. Section X.C.1 contains more details about what the project narrative should contain for the plan for dispensing at least 33% renewable hydrogen through physical pathways.

Q.45 Will the Applicant be required to use the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model to determine carbon intensity?

A.45 See “Guidance for Carbon Intensity Calculations for Hydrogen PON” Inserted below.

Q.46 Can the following be modified: “Section III.C.8, pg. 12 states that “each station” must dispense, at minimum, 33% renewable hydrogen on a per kg basis?” The reason for the question is that Section X.C.1 requires the applicant to describe how “each station or a portfolio of stations” is expected to meet the 33% renewable hydrogen requirement. The paragraph on 33% renewable hydrogen should be modified in parallel with section X.C.1 on page 25 to eliminate any confusion or contradictions.

A.46 No modifications are necessary. The eligibility requirements in Section III.C.8 parallel the Project Narrative requirements described in Section X.C.1. Please refer to the second paragraph in Section III.C.8, page 12, which states in part that, “Alternatively, Applicants may elect to dispense 33% renewable hydrogen from the network of their proposed stations awarded under this solicitation.”

Q.47 The term physical pathway is used in both sections III.C.8 and X.C.1. By definition in the Low Carbon Fuel Standard (LCFS), physical pathway means the following:

> “Physical pathway means the applicable combination of actual fuel delivery methods, such as truck routes, rail lines, gas/liquid pipelines, electricity transmission lines, and any other fuel distribution methods, through which the regulated party reasonably expects the fuel to be transported under contract from the entity that generated or produced the fuel, to any intermediate entities, and ending at the fuel blender, producer, importer, or provider in California.”

Was the intent of the solicitation to describe the “physical pathway?”

A.47 Yes. Energy Commission staff agree with the definition of physical pathway described above.

Q.48 Section X.C.1 requires the Applicant to submit the name of the fuel pathway, along with other required information. In some cases, an Applicant may encounter a situation where a pathway does not exist or is similar to an existing pathway but differs. To resolve this, the Applicant can: (i.) select the closest fuel pathway or b) determine a custom fuel pathway under Method 2A/2B process of the LCFS. Refer to Establishing New Fuel Pathways under the California Low Carbon Fuels Standard concept paper for further details.
http://www.arb.ca.gov/fuels/lcfs/012010newguideline.pdf

A.48 Thank you for the additional information. For more information, see "Guidance for Carbon Intensity (CI) Calculations for Hydrogen PON" below.

Q.49 Why does Section III.C.8 state that "credits may not be used except for process electricity?" The term "process electricity" is not defined anywhere and it is unclear what "credits" refer to (e.g., LCFS credits or other credits). Further, it is unclear why credits cannot be used since Section X.C.1 (page 26) allows for the use of eligible renewable energy certificates registered and verifiable through WREGIS. Both sections III.C.8 and X.C1 should be modified so that it is clear that only renewable energy certificates (RECs) are allowed to meet the 33% requirement.

A.49 Process electricity is the electricity used to create the hydrogen. Pursuant to Section III.C.8, projects that use eligible renewable electricity sources for the process electricity may use that renewable electricity to meet the 33% requirement. Further, Section III.C.8 lists Renewable Energy Certificates (REC) as the only type of credit that is an eligible renewable electricity source. Section X.C.1 clarifies that RECs must be registered and verifiable through Western Renewable Energy Generation Information System (WREGIS) or an equivalent tracking and verification system. Thus, no modifications are necessary.

Q.50 Section III.C.8. Definition of eligible renewable feedstock and electricity sources should be moved to Section X.C.1 (page 26) second bullet from the top where "renewable electricity" and "biogas/renewable feedstock" are required in the application submission. The term "biogas/renewable feedstock" should be changed to "renewable feedstock" since biogas is part of the renewable feedstock list.

A.50 No, the definition of renewable hydrogen shall remain in the Eligibility section of the solicitation (Section III.C.8). The third bullet of Section X.C.1, on page 26, is amended to read (note underline/strikeout):

> "The Energy Commission will verify whether the renewable hydrogen requirement is met. For each station, Applicants must submit the following information: Year, name of pathway, amount of hydrogen dispensed annually per station (in kilograms), <u>eligible</u> ~~biogas/~~renewable feedstock (in standard cubic feet), and <u>eligible</u> renewable electricity <u>sources</u> (in kilowatt hours)."

SPECIAL ITEM OF CLARIFICATION:
"Guidance for Carbon Intensity Calculations for Hydrogen Fuel Infrastructure Solicitation"

1. Background

The Energy Commission requires carbon intensity values from applicants in order to evaluate applications under the scoring criterion for sustainability in Section XII.C.10.

The CI value submitted by each applicant will not be used for regulatory compliance purposes for the LCFS program. The CI values will also not be used to verify SB 1505 regulatory compliance. Therefore, CI values submitted in response to the current hydrogen solicitation do not need to meet the same technical standards for LCFS compliance or SB 1505 compliance.

However, ARFVTP applicants may seek to qualify their fuel products under the LCFS regulation in order to generate LCFS credits. Because hydrogen producers and retailers of hydrogen transportation fuel do not have "compliance" obligations under the LCFS, ARB has created an "opt in" provision to the LCFS regulation to allow hydrogen producers and retailers to voluntarily qualify their low carbon fuels products to generate LCFS credits. Companies will need to meet all applicable LCFS methods standards to "opt in" to the LCFS program.

Energy Commission staff seeks whenever possible to have ARFVTP programs conform as closely as possible to LCFS program requirements in order to ensure uniformity in CI calculations and producer claims. Nonetheless, CI values and calculations may be submitted to the Energy Commission in response to the current hydrogen solicitation that do not fully meet the regulatory technical standards required for LCFS compliance purposes.

2. Calculation of CI Values for Hydrogen Solicitation PON-12-606

The Energy Commission requires three forms of carbon reduction estimates for the hydrogen solicitation. The first is the CI value or rate, expressed in grams of CO2 equivalent per mega joule of energy. The second is total metric tons per annum, and the third is total metric tons over the life of the funded project.

As stated on page 27: "Applicants shall: 1) use a method for assessing carbon intensity values that conforms to the California Air Resources Board's (ARB) Low Carbon Fuel Standard (LCFS) or an alternative methodology approved by the Energy Commission; 2) include all assumptions and calculations; and 3) compare the greenhouse gas emissions reductions of the appropriate petroleum baseline listed on the LCFS website: www.arb.ca.gov/fuels/lcfs/lcfs.htm."

After the carbon intensity value has been established, applicants should calculate the percentage reduction from the petroleum baseline. Applicants should then calculate the total metric tons per year and the total metric tons over the life of the funded project. Please refer to the following sections for information on how to calculate CI values.

3. Calculation of CI Values Using ARB LCFS Methodology

Applicants should first consult the current version of the LCFS Regulation[1] and the following "Lookup Table" for gasoline substitutes from hydrogen to determine if there is a default value for an applicable

[1] Title 17, CCR, Section 95480 and following, LCFS Final Regulation Order, November 26, 2012 http://www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder_112612.pdf

fuel pathway carbon intensity value that fits their production process. Applicants should also familiarize themselves with the appropriate Fuel Pathway documents,[2] which document how lifecycle CI values are determined.

Table 1: Hydrogen Fuel Pathways Published in LCFS Lookup Table, Adjusted by EER Value[3]

Pathway Identifier	Hydrogen Production Process	Carbon Intensity Value (gCO2-e/MJ)	Adjusted Carbon Intensity Value with EER Score of 2.5[4] (light duty fuel cell vehicles)
HYGN001	Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	142.20	56.88
	Hydrogen by central SMR, liquid delivered with 33% renewable (Estimated – For PON-12-606 Use Only)	110.18	44.07
HYGN002	Liquid H2 from central reforming of NG	133.00	53.20
HYGN003	Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	98.80	39.52
	Hydrogen by central SMR, gas delivered with 33% renewable (Estimated – For PON-12-606 Use Only)	78.30	31.32
HYGN004	Compressed H2 from on-site reforming of NG	98.30	39.32
HYGN005	Compressed H2 from on-site reforming with renewable feedstocks	76.10	30.44

Energy Commission staff assumes that most central station hydrogen producers using steam reformation of natural gas will find their applicable process and carbon intensity value listed in one of the default values summarized in the above excerpt from the LCFS Lookup Table; primarily HYGN001 for liquid hydrogen and HYGN003 for gaseous hydrogen. If so, applicants must adjust the CI value for the minimum 33 percent renewable hydrogen content. ARB staff estimates are provided for HYGN001 and HYGN003 as default values that will be accepted by the Energy Commission with appropriate documentation. (Note: pathway HYGN005 is the ARB-supplied default pathway for hydrogen with 1/3 renewable hydrogen content produced using an on-site steam reforming production process.) The CI value must also be adjusted with the EER, or Energy Economy Ratio, a calculated value that reflects the inherent efficiencies of electric drivetrains and fuel cell stacks.

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2 http://www.arb.ca.gov/fuels/lcfs/workgroups/workgroups.htm#pathways

3 Sources: 1) Table 6, Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline, LCFS Final Regulation Order, Section 95480 and following, Title 17 CCR. 2) Estimated carbon intensity values with 1/3 biogas feedstocks.

4 LCFS Final Regulation Order, Table 5.

If the applicant's production process is not listed on Table 6, applicants must then submit a carbon intensity value that is calculated using either Method 2A or 2B[5] as described in the LCFS regulation. Method 2A is a modification of an existing pathway, such as described in HYGN001 to 005 above. Method 2B is an entirely new pathway reflecting new production processes or feedstocks.

The LCFS Reporting Tool[6] is available on the ARB website as another tool and method for calculating greenhouse gas emissions. Although the output of this tool is in metric tons per year of LCFS credits generated, this is effectively the per annum GHG value in metric tons. Applicants must separately calculate the GHG emissions over the lifetime of the project. The Energy Commission will accept CI values contained in this tool or values derived from the Method 2A or 2B process.

4. Manual Calculation of CI Values for Hydrogen Solicitation PON-12-606

If a formal 2A or 2B pathway cannot be determined in the timeframe of this solicitation, Applicants may submit a CI value estimate using a "methodology approved by the Energy Commission." Such alternative methodologies are generally variations on the LCFS 2A method, where an existing fuel pathway is modified to reflect a different energy input, process technology or feedstock. All assumptions and calculations must be clearly shown. Good faith efforts to provide clearly documented CI value calculations will not be penalized for arithmetic errors or inaccurate assumptions. The Energy Commission has technical staff and an outside contractor available to review, and potentially adjust, CI calculations for submitted proposals.

The Greenhouse Gases, Regulated Emissions and Energy Use in Transportation Model, or GREET Model, was developed by Argonne National Laboratory as an open source spreadsheet tool to calculate lifecycle-scale greenhouse gas emissions in the alternative fuels and transportation sector. California GREET is the standard tool used to calculate CI values (CA-GREET version 1.8b).[7] Although not required, the Energy Commission encourages applicants to use CA-GREET because default assumptions on California's electricity mix and other parameters specific to California are already incorporated.

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[5] "Establishing New Fuel Pathways Under the Low Carbon Fuel Standard: Procedures and Guidelines for Regulated Parties and Fuel Producers," August 2010, California Air Resources Board, http://www.arb.ca.gov/fuels/lcfs/122310-new-pathways-guid.pdf

[6] http://www.arb.ca.gov/fuels/lcfs/reportingtool/reportingtool.htm

[7] http://www.arb.ca.gov/fuels/lcfs/lcfs.htm