LOW CARBON FUEL STANDARD
ANNUAL UPDATES TO LOOKUP TABLE PATHWAYS

2021 Carbon Intensity Values for

California Average Grid Electricity Used as a Transportation Fuel in California and Electricity Supplied Under the Smart Charging or Smart Electrolysis Provision

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I. Summary

This document provides the proposed carbon intensity (CI) values and a detailed description of the 2021 annual update to the two Lookup Table pathways for electricity under the Low Carbon Fuel Standard (LCFS). Section 95488.5(d) of the LCFS regulation[1] directs the Executive Officer to update the CI annually for these two Lookup Table pathways using the methodology described in Section E of the Lookup Table Pathways Technical Support Documentation.[2] Upon certification, the updated pathway CI values will be available for reporting fuel transactions that occur between January 1 and December 31, 2021. The proposed CI values and updated Fuel Pathway codes are shown in Tables 1 and 2.

Table 1. Proposed CI Values for 2021 Annual Update to Electricity Lookup Table Pathways

Fuel Pathway Code	Fuel Pathway Description	CI gCO_2e/MJ
ELC000L00072021	California average grid electricity used as a transportation fuel in California (subject to annual updates)	75.93
ELCT	Electricity supplied under the smart charging or smart electrolysis provision (subject to annual updates)	See Table 2

[1] All citations to the LCFS Regulation are found in Title 17, California Code of Regulations (CCR), sections 95480-95503

[2] CA-GREET3.0 Lookup Table Pathways Technical Support Documentation. August 13, 2018. California Air Resources Board. Available at: http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

Table 2. Proposed CI Values (gCO_2e/MJ) for Smart Charging or Smart Electrolysis in 2021

Hourly Window	Q1	Q2	Q3	Q4
12:01 AM – 1:00 AM	78.62	78.98	80.59	84.58
1:01 AM – 2:00 AM	78.61	78.52	78.73	81.93
2:01 AM – 3:00 AM	78.61	77.60	78.49	80.46
3:01 AM – 4:00 AM	78.61	77.55	78.41	79.98
4:01 AM – 5:00 AM	78.74	78.64	78.35	81.02
5:01 AM – 6:00 AM	82.41	84.58	79.21	90.21
6:01 AM – 7:00 AM	101.27	98.14	88.32	111.00
7:01 AM – 8:00 AM	105.99	26.35	85.14	110.15
8:01 AM – 9:00 AM	72.59	2.19	54.57	90.74
9:01 AM – 10:00 AM	27.50	1.59	6.78	37.41
10:01 AM – 11:00 AM	27.14	2.86	11.77	30.05
11:01 AM – 12:00 PM	26.82	45.35	19.86	33.68
12:01 PM – 1:00 PM	0.00	48.20	29.32	35.06
1:01 PM – 2:00 PM	0.00	49.94	83.21	36.78
2:01 PM – 3:00 PM	26.76	53.22	90.17	56.91
3:01 PM – 4:00 PM	52.40	57.69	93.83	72.98
4:01 PM – 5:00 PM	59.81	24.01	98.63	115.78
5:01 PM – 6:00 PM	98.08	28.97	121.69	136.97
6:01 PM – 7:00 PM	128.03	85.93	134.38	140.33
7:01 PM – 8:00 PM	122.74	139.08	142.06	135.65
8:01 PM – 9:00 PM	112.20	139.48	131.15	127.94
9:01 PM – 10:00 PM	93.64	115.44	111.14	114.00
10:01 PM – 11:00 PM	81.91	87.46	94.51	100.83
11:01 PM – 12:00 AM	78.74	80.25	84.53	88.33

These updates reflect changes in the carbon intensity of California grid electricity driven by rapidly increasing contributions from low-carbon sources in the California electricity mix (Figure 1) due to mandates driven by the Renewable Portfolio Standard (RPS), requirements related to integrated resource planning (IRP)[3], the inclusion of Cap-and-Trade carbon pricing in dispatch models, and other structural or systemic changes.

[3] Integrated Resource Plan and Long Term Procurement Plan. California Public Utilities Commission. https://www.cpuc.ca.gov/irp/

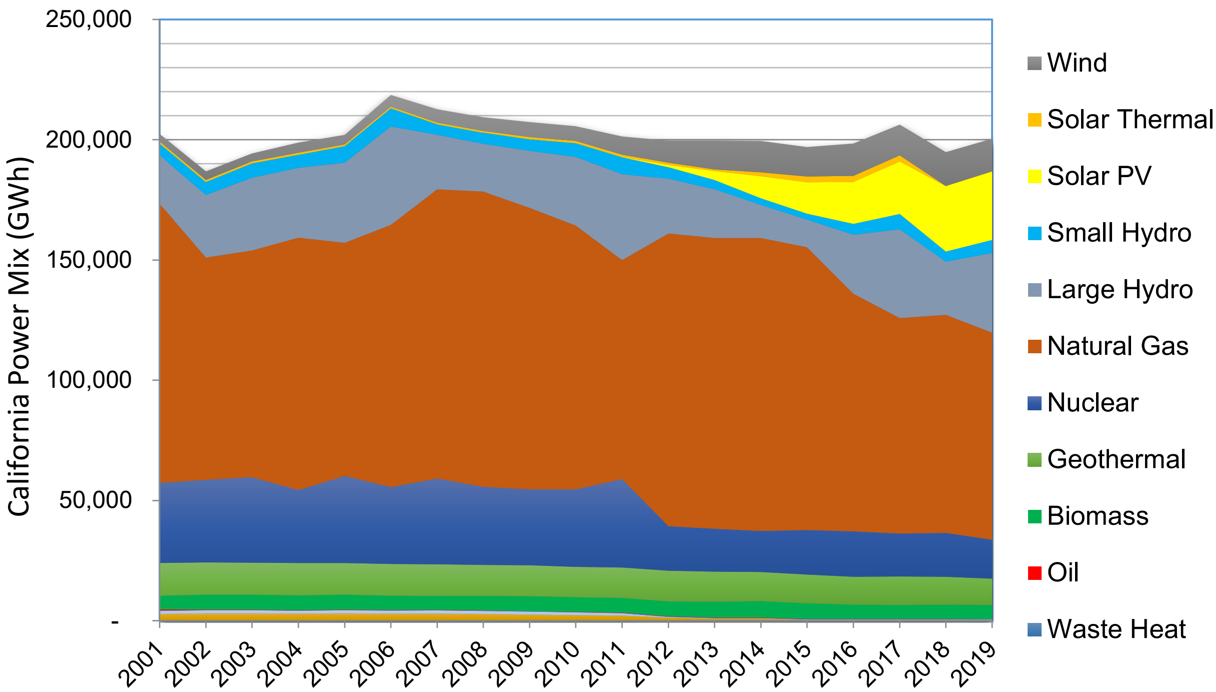

Figure 1. Total System Electric Mix in California in Gigawatt Hours (GWh)[4]

[4] Data source: Total System Electric Generation, 2012-2019. California Energy Commission. Accessed 9/2020. https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html

II. Pathway Details, Assumptions, and Calculations

1. California Average Grid Electricity Used as a Transportation Fuel in California

Pursuant to the methodology specified in the Lookup Table Pathways Technical Support Documentation (August 13, 2018), the "Power Generation" stage of the California average grid electricity pathway is modeled in CA-GREET3.0 using the California Power Mix from the Total System Electric Generation dataset provided by the California Energy Commission (CEC). The "Feedstock Production" stage is modeled using the U.S. average mix from the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID2014v2). Only the "Power Generation" stage of the life cycle is updated using Total System Electric Generation for the 2019 data year. The CEC's California Power Mix for 2018 and 2019 data years are compared in Table 1-1. The resulting CI for use in 2021 reporting is calculated, as described below, to be **75.93** gCO_2e/MJ, a decrease from the CI of 82.92 gCO_2e/MJ certified for reporting year 2020.

Table 1-1. California Power Mix for Data Years 2018 and 2019[5]

	2018 CEC		2019 CEC	
	% Mix	GWh	% Mix	GWh
Residual oil	0.17%	474	0.16%	458
Natural Gas	45.44%	129,739	41.57%	115,433
Coal	3.30%	9,433	2.96%	8,233
Nuclear	9.05%	25,841	8.98%	24,945
Biomass	2.35%	6,707	2.44%	6,787
Hydro	12.29%	35,082	16.85%	46,249
Geothermal	4.54%	12,968	4.77%	13,260
Wind	11.46%	32,711	10.17%	28,249
Solar	11.40%	32,533	12.28%	34,090
Total	100%	**285,488**	100%	**277,704**

As described in the Technical Support Documentation, in order to harmonize the resources reported by CEC with those in CA-GREET3.0, the "Other Petroleum Sources" category from CEC's mix was treated as "Residual Oil", while the "Unspecified Sources of Power" category was assumed to be from "Natural Gas" in CA-GREET3.0.

Table 1-2 details the updated contribution of each power resource in energy input, emission factor and CI. This Table provides details of emission factors matched to

[5] 2018 California Total System Electric Generation data from California Energy Commission (CEC) website, accessed 09/2020: https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html

appropriate resource mixes to calculate an average CI for electricity, which will be used for reporting in 2021 after completion of a public comment period.

Table 1-2. Summary of CI for California Average Grid Electricity Used as a Transportation Fuel in California for 2019 data *

	Electricity Resources Mix	Energy Inputs, Btu/MMBtu	Feedstock Production Contribution to CI, $gCO_2e/MMBtu$	Power Generation Emission Factor, $gCO_2e/MMBtu$	Power Generation Contribution to CI, $gCO_2e/MMBtu$
Residual Oil	0.16%	5,085	75	253,578	434
Natural Gas	41.57%**	923,958	12,773	123,600	54,952
Coal	2.96%	91,233	503	289,777	9,174
Nuclear	8.98%	96,043	348	0	0
Biomass	2.44%	115,470	259	8,713	227
Hydro	16.65%	161,067	0	0	0
Geothermal	4.77%	51,039	0	26,669	1,361
Wind	10.17%	98,381	0	0	0
Solar PV	12.28%	118,793	0	0	0
Total	100%		**13,958**		**66,149**
CI, gCO_2e/MJ			13.23		62.70
Total CI, gCO_2e/MJ					**75.93**

* Values may not sum to the total due to rounding.
** In the CA-GREET3.0 model, all undefined energy resources are assumed to be from natural gas. This value represents the sum of the reported natural gas used in the electricity mix (34.23%) and the undefined energy categories (7.34%), as the total share of natural gas (41.57%) in the CA Electricity Resources Mix. Similarly, other petroleum in the CEC power mix was treated as Residual Oil in the CA-GREET3.0.

2. California Average Grid Electricity Supplied under the Smart Charging or Smart Electrolysis Provision

2.1. Description of smart charging or smart electrolysis CI values:

The carbon intensity values for smart charging or smart electrolysis provisions are calculated based on the marginal emission rates determined using the Avoided Cost Calculator (March 2018) developed by the California Public Utilities Commission.[6] A set of algorithmically neutral carbon intensity values are determined for each hour of the day, for the four quarters of the year, to represent the average marginal emission rates for EV charging or electrolytic hydrogen production that takes place during these times. Shifting EV charging or electrolysis could result in additional emission reductions as compared to Average Grid Electricity CI during the periods when the marginal emission reductions are low.

2.2. Calculation of normalized average marginal emission rates for California Average Grid Electricity:

For calculation of marginal emission rates in the Avoided Cost Calculator, natural gas is assumed to be the marginal fuel for electricity generation in California in all hours and the hourly emissions rate of the marginal generator is calculated based on the day-ahead market price curve. The relation between market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency (i.e. less economical) generators to operate, resulting in corresponding, increased rates of emissions at the margin. This relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of gas turbine technology heat rates. Additionally, if the implied heat rate is calculated to be at or below zero, it is then assumed that the system is in a period of over generation and therefore the marginal emission rate is correspondingly zero as well.

The Avoided Cost Calculator estimates marginal emission rates for utilities in Northern and Southern California, which are based on the normalized hourly day-ahead heat rate profiles for CAISO NP-15 and SP-15 regions. Statewide average marginal emission rates for 2021, weighted by load, are calculated based on the load profile of large load serving entities (LSE) in the two geographical areas, Pacific Gas and Electric (PG&E) in Northern California and Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) in Southern California. Based on the CAISO OASIS data[7] for all three utilities from January 1, 2019 through December 31, 2019, approximately 45% of the

[6] Energy and Environmental Economics, Inc. [Avoided Cost Calculator](http://www.cpuc.ca.gov/General.aspx?id=5267), May 2018. Incorporated by reference into the LCFS Regulation, section 95481(a)(10). Accessed 8/2019. Available from the California Public Utilities Commission website at: http://www.cpuc.ca.gov/General.aspx?id=5267
[7] CAISO Demand Forecast – Actual. Accessed: 12/2019 Available at: http://oasis.caiso.com/mrioasis/logon.do

annual average hourly load is served in Northern California and 55% is served in Southern California, as shown in Table 2-1.

Table 2-1. The average hourly load of the large load serving entities and their share of the overall load in California in 2019

Load-Serving Entity	Average Hourly Load (MW)[8]	% of Load
PG&E	11,316	45%
SCE	11,370	46%
SDG&E	2,197	9%
Total	24,883	100%

The resulting statewide average marginal emission rates for California Grid Average Electricity are normalized to the annual average California Grid emissions rate over the year for each hourly window for the four quarters of the year, as shown in Table 2-2.

Table 2-2. Normalized Marginal Emission Rates for California Grid Average Electricity for 2021

Hourly Window	Q1	Q2	Q3	Q4
12:01 AM – 1:00 AM	1.0355	1.0402	1.0614	1.1139
1:01 AM – 2:00 AM	1.0353	1.0341	1.0368	1.0790
2:01 AM – 3:00 AM	1.0353	1.0220	1.0337	1.0596
3:01 AM – 4:00 AM	1.0353	1.0213	1.0327	1.0533
4:01 AM – 5:00 AM	1.0370	1.0357	1.0319	1.0670
5:01 AM – 6:00 AM	1.0854	1.1139	1.0433	1.1880
6:01 AM – 7:00 AM	1.3337	1.2925	1.1631	1.4618
7:01 AM – 8:00 AM	1.3958	0.3470	1.1213	1.4507
8:01 AM – 9:00 AM	0.9560	0.0289	0.7187	1.1950
9:01 AM – 10:00 AM	0.3622	0.0210	0.0893	0.4927
10:01 AM – 11:00 AM	0.3575	0.0377	0.1551	0.3957
11:01 AM – 12:00 PM	0.3533	0.5973	0.2616	0.4435
12:01 PM – 1:00 PM	0.0000	0.6348	0.3861	0.4618
1:01 PM – 2:00 PM	0.0000	0.6577	1.0959	0.4844
2:01 PM – 3:00 PM	0.3525	0.7009	1.1875	0.7496
3:01 PM – 4:00 PM	0.6901	0.7598	1.2357	0.9612
4:01 PM – 5:00 PM	0.7877	0.3162	1.2990	1.5248
5:01 PM – 6:00 PM	1.2917	0.3815	1.6026	1.8039
6:01 PM – 7:00 PM	1.6861	1.1316	1.7698	1.8482
7:01 PM – 8:00 PM	1.6164	1.8317	1.8709	1.7865
8:01 PM – 9:00 PM	1.4777	1.8370	1.7272	1.6850

[8] Average hourly load is calculated by taking the average load for the load served for each hour in the year

Hourly Window	Q1	Q2	Q3	Q4
9:01 PM – 10:00 PM	1.2332	1.5204	1.4637	1.5014
10:01 PM – 11:00 PM	1.0787	1.1519	1.2447	1.3279
11:01 PM – 12:00 AM	1.0370	1.0569	1.1133	1.1632

2.3. Calculation of smart charging or smart electrolysis CI values:

The carbon intensity values for smart charging or smart electrolysis for a given time period is determined using the California Average Grid Electricity CI and the normalized marginal emission rates for that period. The carbon intensity values calculated for smart charging or smart electrolysis pathways in 2021 are shown in Table 2.

APPENDIX

DETAILED CALCULATIONS OF THE CARBON INTENSITY FOR ELECTRICITY USED AS A TRANSPORTATION FUEL

This Appendix provides details of emission factors, combustion technologies, energy conversion efficiencies derived from CA-GREET3.0 and calculations to facilitate tracking of values used in Table 1-2.

Table A.1. Summary of Combustion Technology Shares and Energy Conversion Efficiencies for California Average Grid Electricity Used as a Transportation Fuel in California in 2021

	Emission Factors of Combustion Technologies in CA, gCO_2e/kWh	Combustion Technology Shares for a Given Plant Fuel Type in CA	Power Plant Energy Conversion Efficiency in CA
Residual Oil-Fired Power Plants			
Boiler	858.87	72.4%	33.9%
Internal Combustion Engine	746.79	15.5%	39.0%
Gas Turbine	1,055.11	12.1%	27.6%
Weighted Average			33.65%
Natural Gas-Fired Power Plants			
Boiler	634.08	6.4%	32.0%
Simple-cycle gas turbine	618.58	3.3%	32.8%
Combined-cycle gas turbine	397.17	89.2%	51.1%
Internal Combustion Engine	588.66	1.1%	34.4%
Weighted Average			48.12%
Coal-Fired Power Plants			
Boiler	988.76	100.0%	34.7%
IGCC	985.78	0.0%	34.8%
Weighted Average			34.70%
Biomass Power Plants			
Boiler	29.73	100.0%	22.6%
IGCC	28.69	0.0%	34.8%
Weighted Average			22.60%
Nuclear	1.21	100%	100%
Hydro	0	38%	100%
Geothermal	0	10.9%	100%
Wind	0	23.2%	100%
Solar PV	0	28%	100%

1) Calculation of contribution to emissions from Natural Gas use in Table 1-2:

Natural gas fired power plants (Table A.1) use four combustion technologies: boiler, simple-cycle gas turbine, combined-cycle gas turbine and internal combustion engine. In California, the shares of these four technologies are 6.4%, 3.3%, 89.2%, and 1.1%, respectively. Furthermore, the energy conversion efficiencies of these four technologies are 32.0%, 32.8%, 51.1% and 34.4%%, respectively. The combustion technology shares and their energy conversion efficiencies were calculated using aggregated data from EIA[9]. Complete details are available in Argonne's 2013 report[10].

Using these values from Table A.1,
For Natural Gas (NG) Feedstock Production, the NG energy input is

$$\frac{41.57\%}{48.12\% \times (1 - 6.5\%)} \times 10^6 \text{Btu/MMBtu} = 923{,}958 \text{ Btu/MMBtu;}$$

where:

Electricity Resources Mix share of NG = 41.57%;

Loss in electricity transmission = 6.5%; and

Power Plant Energy Conversion Efficiency (see Table A.1) =

$$\frac{1}{(6.4\% \div 32.0\%) + (3.3\% \div 32.8\%) + (89.2\% \div 51.1\%) + (1.1\% \div 34.4\%)} = 48.12\%$$

The contribution of NG to the feedstock production CI is:

$$\frac{923{,}958 \text{ Btu/MMBtu}}{10^6 \text{Btu/MMBtu}} \times 13{,}824 \text{ gCO}_2\text{e/MMBtu} = \mathbf{12{,}773} \text{ gCO}_2\text{e/MMBtu } (\mathbf{12.11} \text{ gCO}_2\text{e/MJ})$$

where:

Upstream EF of NG used in power plant = 13,824 gCO_2e/MMBtu
(CI value of the "Natural Gas for Electricity Generation" pathway in the NG tab).

For Natural Gas in Electricity Production, the contribution of NG to power generation CI is:

$$\frac{\mathbf{123{,}600} \text{ gCO}_2\text{e/MMBtu} \times 41.57\%}{(1\text{-}6.5\%)} = \mathbf{54{,}952} \text{ gCO}_2\text{e/MMBtu } (\mathbf{52.08} \text{ gCO}_2\text{e/MJ})$$

where:

EF of Electricity generation from NG (see Table 1.2) =
[(634.08 gCO_2/kWh × 6.4%) + (618.58 gCO_2/kWh × 3.3%) + (397.17 gCO_2/kWh × 89.2%) + (588.66 gCO_2/kWh × 1.1%)] × 293.07 kWh/MMBtu = **123,600** gCO_2/MMBtu

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[9] U.S. Energy Information Administration. Form EIA-923 detailed data, accessed 2017. http://www.eia.gov/electricity/data/eia923

[10] Hao Cai, Michael Wang, Amgad Elgowainy, Jeongwoo Han. Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010. 2013. https://greet.es.anl.gov/publication-electricity-13

2) Calculation of contribution to emissions from Residual Oil use in Table 1-2:

Residual oil-fired power plants use three combustion technologies: boiler, internal combustion engine, and gas turbine. In California, the shares of these three technologies are 72.4%, 15.5%, and 12.1%, respectively. Furthermore, the energy conversion efficiencies of these three technologies are 33.9%, 39.0%, and 27.6%, respectively. The combustion technology shares and their energy conversion efficiencies were calculated using aggregated data from and details are available in Argonne's 2013 report as detailed in section (1) above.

For Residual Oil (RO) Feedstock Production, the RO energy input is

$$\frac{0.16\%}{33.65\% \times (1 - 6.5\%)} \times 10^{6}\text{Btu/MMBtu} = 5{,}085 \text{ Btu/MMBtu;}$$

where:

Electricity Resources Mix share of Residual Oil = 0.16%;

Loss in electricity transmission = 6.5%; and

Power Plant Energy Conversion Efficiency (see Table A.1 above) =

$$\frac{1}{(72.4\% \div 33.9\%) + (15.5\% \div 39\%) + (12.1\% \div 27.6\%)} = 33.65\%$$

The contribution of RO to the feedstock production CI is:

$$\frac{5{,}085 \text{ Btu/MMBtu}}{10^{6}\text{Btu/MMBtu}} \times 14{,}820 \text{ gCO}_2\text{e/MMBtu} = \mathbf{75.36} \text{ gCO}_2\text{e/MMBtu } (\mathbf{0.07} \text{ gCO}_2\text{e/MJ})$$

where:

Upstream EF of RO use in power plant = 14,820 gCO_2e/MMBtu
(CI value of the "Petroleum" tab, RO and Crude sections).

For RO in Electricity Production, the contribution of RO to the power generation CI is:

$$\frac{\mathbf{253{,}578} \text{ gCO}_2\text{e/MMBtu} \times 0.16\%}{(1\text{-}6.5\%)} = \mathbf{433.93} \text{ gCO}_2\text{e/MMBtu } (\mathbf{0.41} \text{ gCO}_2\text{e/MJ})$$

where:

EF of Electricity generation from RO (see Table 1.2) =
[(858.87 gCO_2/kWh × 72.4%) + (746.79 gCO_2/kWh × 15.5%) + (1,055.11 gCO_2/kWh × 12.10%)] × 293.07 kWh/MMBtu = **253,578** gCO_2/MMBtu

3) Calculation of contribution to emissions from Coal use in Table 1-2:

For Coal as Feedstock Production, the coal energy input is

$$\frac{2.96\%}{34.70\% \times (1 - 6.5\%)} \times 10^6 \text{Btu/MMBtu} = 91{,}233 \text{ Btu/MMBtu};$$

where:

Electricity Resources Mix share of Coal = 2.96%;

Loss in electricity transmission = 6.5%; and

Power Plant Energy Conversion Efficiency (see Table A.1 above) =

$$\frac{1}{(100\% \div 34.70\%) + (0\% \div 34.80\%)} = 34.70\%$$

The contribution of coal to the feedstock production CI is:

$$\frac{91{,}233 \text{ Btu/MMBtu}}{10^6 \text{Btu/MMBtu}} \times 5{,}515 \text{ gCO}_2\text{e/MMBtu} = \mathbf{503.12} \text{ gCO}_2\text{e/MMBtu } (\mathbf{0.48} \text{ gCO}_2\text{e/MJ})$$

where:

Upstream EF of coal use in power plant = 5,515 gCO_2e/MMBtu
(CI value of the “Coal” tab).

For Coal in Electricity Production, the contribution of coal to the power generation CI is:

$$\frac{\mathbf{289{,}777} \text{ gCO}_2\text{e/MMBtu} \times 2.96\%}{(1-6.5\%)} = \mathbf{9{,}174} \text{ gCO}_2\text{e/MMBtu } (\mathbf{8.69} \text{ gCO}_2\text{e/MJ})$$

where:

EF of Electricity generation from coal (see Table 1.2) =
[(988.76 gCO_2/kWh × 100%) + (985.78 gCO_2/kWh × 0%)] × 293.07 kWh/MMBtu =
289,777 gCO_2/MMBtu

4) Calculation of contribution to emissions from Biomass use in Table 1-2:

The CA-GREET 3.0 considers forest residue as biomass used in power generation plant. For Biomass as Feedstock Production, the biomass energy input is

$$\frac{2.44\%}{22.60\% \times (1 - 6.5\%)} \times 10^6 \text{Btu/MMBtu} = \mathbf{115{,}470} \text{ Btu/MMBtu};$$

where:

Electricity Resources Mix share of Biomass = 2.44%;

Loss in electricity transmission = 6.5%; and

Power Plant Energy Conversion Efficiency (see Table A.1 above) =

$$\frac{1}{(100\% \div 22.6\%) + (0\% \div 34.80\%)} = 22.60\%$$

The contribution of biomass to the feedstock production CI is:

$$\frac{115{,}470\ \text{Btu/MMBtu}}{10^6\text{Btu/MMBtu}} \times 2{,}242\ \text{gCO}_2\text{e/MMBtu} = \mathbf{259}\ \text{gCO}_2\text{e/MMBtu}\ (\mathbf{0.25}\ \text{gCO}_2\text{e/MJ})$$

where:

Upstream EF of biomass use in power plant = 2,242 gCO_2e/MMBtu
(CI value of the "EtOH" tab, "Forest Residue" section).

For Biomass use in Electricity Production, the contribution of biomass to the power generation CI is:

$$\frac{\mathbf{8{,}713}\ \text{gCO}_2\text{e/MMBtu} \times 2.44\%}{(1\text{-}6.5\%)} = \mathbf{227}\ \text{gCO}_2\text{e/MMBtu}\ (\mathbf{0.22}\ \text{gCO}_2\text{e/MJ})$$

where:

EF of Electricity generation from biomass (see Table 1.2) =
[(29.73 gCO_2/kWh × 100%) + (28.69 gCO_2/kWh × 0%)] × 293.07 kWh/MMBtu = **8,713** gCO_2/MMBtu

5) Calculation of contribution to emissions from Nuclear use in Table 1-2:

CA-GREET 3.0 model assumes electricity from nuclear is generated in the Light Water Reactor and Uranium is U-235. Emissions are mostly from upstream of Nuclear energy feedstock (Uranium mining and transport):

Power generation share of nuclear = 8.98%;

Loss in electricity transmission = 6.5%;
Conversion factor for nuclear power plants = 6.926 MWh/g of U-235
EF of Uranium mining and transport = 85,662 gCO_2e/gram of U-235

$$\frac{\mathbf{1{,}000{,}000\ Btu} \times 8.98\%}{(1\text{-}6.5\%)} = \mathbf{96{,}043\ Btu}/\text{MMBtu}$$

For Nuclear use in Electricity Production, the contribution of nuclear to the power generation CI is:

$$\frac{\mathbf{85{,}662}\ \text{gCO}_2\text{e/grams of U-235} \times 96{,}043\ \text{Btu/MMBtu}}{(6.926\ \text{MWh/g U-235} \times 1{,}000 \times 3{,}412.14\ \text{Btu/kWh})} = \mathbf{348}\ \text{gCO}_2\text{e/MMBtu}\ (\mathbf{0.33}\ \text{gCO}_2\text{e/MJ})$$

6) Calculation of contribution to emissions from Geothermal in Table 1-2:

Fugitive emissions from geo-fluid is 91 gCO_2e/kWh (or 26,669 gCO_2/MMBtu) in operations involving geothermal energy used in the production of electricity. CO_2 emissions are calculated as:

$$\frac{\mathbf{91}\ gCO_2e/kWh \times 4.77\%}{(1-6.5\%)} = 1{,}361.2\ gCO_2e/MMBtu\ \ (\mathbf{1.29}\ gCO_2e/MJ)$$

Where:
Power generation share of geothermal = 10.9%;

Total renewable sources = 43.90%

Share allocated to geothermal = 43.90% x 10.90% = 4.77%

Loss in electricity transmission = 6.5%;
Energy inputs: 4.77% x 1,000,000 Btu/MMBtu/(1-6.5%) = 51,039 Btu/MMBtu