San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

APR 21 2014

Douglas Wheeler
Hanford LP
P O Box 2420
Alameda, CA 94051

Re: Notice of Preliminary Decision – Emission Reduction Credits
Facility Number: C-603
Project Number: C-1120606

Dear Mr. Wheeler:

Enclosed for your review and comment is the District's analysis of Hanford LP's application for Emission Reduction Credits (ERCs) resulting from the shutdown of one 320 MMBtu/hr petroleum coke fired fluidized bed combustor driving a 30 MW steam turbine, at 10596 Idaho Avenue, Hanford, CA. The quantity of ERCs proposed for banking is 175,579 metric tons CO2e/yr.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice comment period, the District intends to the issue the ERCs. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Dustin Brown of Permit Services at (559) 230-5932.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:DDB

Enclosures

cc: Mike Tollstrup, CARB (w/enclosure) via email
cc: Gerardo C. Rios, EPA (w/enclosure) via email

Greenhouse Gas Emission Reduction Credit Banking Application Review

Shutdown of 30 MW Petroleum Coke Fired Fluidized Bed Combustor

Processing Engineer: Dustin Brown
Lead Engineer: Joven Refuerzo
Date: April 16, 2014

Facility Name:	Hanford LP
Mailing Address:	2121 N. California Boulevard, Suite 290 Walnut Creek, CA 92648
Primary Contact:	Douglas Wheeler – Vice President
Phone:	(714) 600-1391
Email:	dwheeler@gwfpower.com
Facility Location:	10596 Idaho Avenue Hanford, CA 93230
Deemed Complete Date:	November 6, 2013
Project Number:	C-1120606

I. Summary:

Hanford LP operated an electrical generation facility in Hanford, CA. The facility ceased production operations in August of 2011 and began disassembling and removing the equipment associated with the 320 MMBtu/hr petroleum coke, natural gas or fuel oil #2 fired fluidized bed combustor driving a 30 MW electrical generator (PTO C-603-1) and one 15,466 gallon per minute cooling tower (PTO C-603-16) from the site in February of 2012. The facility previously applied for, and received, criteria pollutant emission reduction credits (ERC's) for the actual emission reductions (AER's) of NO_X, CO, VOC, PM_{10} and SO_X emissions resulting from the shutdown of these pieces of equipment on July 9, 2012 (reference project C-1120248).

Subsequently, on January 31, 2012, Hanford LP submitted a second application to bank the Greenhouse Gas (GHG) AER's that also resulted from the shutdown of these pieces of equipment. Of the two permitted pieces of equipment referenced above, GHG emissions were potentially only generated by the 320 MMBtu/hr petroleum coke, natural gas or fuel oil #2 fired fluidized bed combustor driving a 30 MW electrical generator. Therefore, this project will only address the GHG reductions associated from the shutdown of this permit unit.

Hanford LP previously surrendered Permits to Operate (PTO) C-603-1-11. A copy of the surrendered PTO is included in Attachment A of this document.

Selection of Geographical Boundary for Determining Permanence of the GHG Emission Reduction

Rule 2301 contains several eligibility criteria for emission reduction credit banking, including that the emission reduction must be permanent. When determining the geographical boundary in which the emission reduction is determined to be permanent, the applicant may consider how the GHG ERC may likely be used.

Please note that the while Rule 2301 allows facilities to receive ERCs for GHG emission reductions, the District does not have any requirements on the use of GHG ERCs. However, it is anticipated that the likely uses of such GHG ERCs would be their future retirement as GHG mitigation in the California Environmental Quality Act (CEQA) process.

Pursuant to CEQA, lead agencies must consider the environmental impact of GHG emissions from a project and may require that such GHG emissions be mitigated. In evaluating various mitigation techniques, including the retirement of GHG ERCs, the lead agency must determine if the proposed mitigation technique adequately mitigates the projects GHG emission increase.

When a lead agency determines if the retirement of a particular GHG ERC provides adequate GHG mitigation for a project, the lead agency may choose to consider the location where the GHG ERC was generated and the geographical boundary used to determine the permanence of the emission reduction. In making this determination, the lead agency may conclude that the retirement of a particular GHG ERC would provide adequate mitigation for projects within that same geographical boundary. Again, that determination will be made by the lead agency for any particular project.

For this application, the facility has selected the State of California as the geographical boundary for which the emission reductions are permanent. Information has been provided by Hanford LP (Attachment E) and the California Energy Commission (Attachment F) on the future power demands and the power production levels within the State of California, classified by fuel source type, to validate this geographical boundary selection. Using this geographical boundary, it was determined that the GHG emission reduction is permanent within the State of California.

The District has proposed to issue the GHG ERCs for Carbon Dioxide equivalent (CO2e). The amount of bankable CO2e emissions is shown in the table below.

Bankable GHG Emissions	
Pollutant	Metric Tons/Year
CO2e	175,579

II. Applicable Rules:

Rule 2301 - Emission Reduction Credit Banking (last amended 1/19/12)

III. Location of Reductions:

Physical Location of Equipment: 10596 Idaho Avenue in Hanford, CA.

IV. Method of Generating Reductions:

The AER's were generated by shutting down one 320 MMBtu/hr petroleum coke, natural gas or fuel oil #2 fired fluidized bed combustor driving a 30 MW electrical generator. The equipment description for this unit is as follows:

C-603-1-11:

30 MW FLUIDIZED BED COMBUSTOR FUELED BY PETROLEUM COKE, NATURAL GAS, AND NO. 2 FUEL OIL UP TO 320 MMBTU/HR

V. Calculations:

A. Assumptions

- The CO2e emission factor from the combustion of petroleum coke, natural gas and fuel oil #2 includes GHG emissions of CO_2, CH_4 and N_2O, where the total emission factor includes the summation of each of the compounds multiplied by their Global Warming Potential (GWP)
- Carbon dioxide equivalents (CO2e) are found by multiplying the mass emissions of a GHG by its global warming potential (GWP). For combustion sources, GHG's include the following three "well-mixed" compounds: carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O). The District has adopted the following GWPs per District Rule 2301 (*Emission Reduction Credit Banking*):

  $CO_2 = 1$
  $CH_4 = 21$
  $N_20 = 310$

- Conversion: 1 short ton = 2,000 pounds
- Conversion: 1,000 kg = 1 metric ton
- Conversion: 1 short ton = 0.9072 metric tons
- The fluidized bed combustor was only fired on petroleum coke and PUC-regulated natural gas (fuel usage records provided by the applicant under project C-1090909 and included in Attachment C)
- The heating value of the petroleum coke used at this facility is 30.00 MMBtu/short ton (40 CFR 98, Supbart C, Table C-1),
- In order to reduce SO_X emissions, the facility injected sorbent in to the combustion chamber of the fluidized bed boiler (reference condition 21 on current permit C-603-1-11). The sorbent used at this facility was limestone. The calcium carbonate (CaCO3) content of the limestone used at this facility was typically 95% (provided by the applicant, reference Attachment C)

B. Emission Factors (EF's)

The EFs used to calculate the AERs are as follows:

C-603-1 (320 MMBtu/hr fluidized bed combustor):

Petroleum Coke Combustion:

The following petroleum coke EFs were taken from EPA 40 CFR Part 98, Subpart C, Tables C-1 and C-2 (see Attachment D):

102.41 kg-CO2/MMBtu
0.011 kg-CH4/MMBtu
0.0016 kg-N20MMBtu

The GWPs of CO_2, CH_4, and N_20 will be combined with the combustion emission factors into a single CO2e emission factor.

CO2e EF = [(102.41 kg-CO_2/MMBtu x 1 lb-CO2e/lb-CO_2) + (0.011 kg-CH_4/MMBtu × 21 lb-CO2e/lb-CH_4) + (0.0016 kg-N_20/MMBtu × 310 lb-CO2e/lb-N_2O)]

CO2e EF = 103.14 kg/MMBtu (equivalent to 0.10314 metric ton/MMBtu)

Natural Gas Combustion:

The following natural gas EFs were taken from EPA 40 CFR Part 98, Subpart C, Tables C-1 and C-2 (see Attachment D):

53.02 kg-CO2/MMBtu
0.001 kg-CH4/MMBtu
0.0001 kg-N20MMBtu

The GWPs of CO_2, CH_4, and N_20 will be combined with the combustion emission factors into a single CO2e emission factor.

CO2e EF = [(53.02 kg-CO_2/MMBtu x 1 lb-CO2e/lb-CO_2) + (0.001 kg-CH_4/MMBtu × 21 lb-CO2e/lb-CH_4) + (0.0001 kg-N_20/MMBtu × 310 lb-CO2e/lb-N_2O)]

CO2e EF = 53.07 kg/MMBtu (equivalent to 0.05307 metric ton/MMBtu)

Sorbent Usage:

Calcium carbonate was injected in to the fluidized bed combustor in order to reduce SO_X emissions. Calcium carbonate has a chemical formula of $CaCO_3$. Under the heat experienced in the combustion chamber of the fluidized bed combustor, the calcium carbonate decomposed in to Calcium Oxide (CaO) and Carbon Dioxide (CO_2). Using a stoichiometric mass balance and the molecular weights of each element, the amount of CO2 generated by the use of calcium carbonate can be determined as follows:

<u>Molecular Weights:</u>

Calcium (Ca) – 40.078
Oxygen (O) – 15.999
Carbon (C) – 12.0107

Stoichiometric Balance:

$CaCO_3 \rightarrow CaO + CO_2$

$[40.078 + 12.0107 + (3 \times 15.999)] \rightarrow [40.078 + 15.999] + [12.0107 + (2 \times 15.999)]$

100.0857 ($CaCO_3$) → 56.077 (CaO) + 44.0087 (CO_2)

44.0087 (CO2) / 100.0857 (CaCO3) = 44% is CO_2

So for every one pound of calcium carbonate used, you get 0.44 pounds of CO_2 generated. In addition, based on the discussion above and information provided by the applicant, the calcium carbonate content of the sorbent used at the facility was 95%.

Therefore, the amount of CO2 generated for each pound of sorbent used at this facility can be determined as follows:

CO_2 EF = lb-CO_2/lb $CaCO_3$ x $CaCO_3$ Content of Sorbent Used (lb-$CaCO_3$/lb sorbent)
CO_2 EF = 0.44 lb-CO_2/lb $CaCO_3$ x 0.95 lb-$CaCO_3$/lb sorbent used

CO2 EF = 0.418 lb CO_2/lb sorbent used

The CO2e emission factor can be determined using the GWP listed above:

CO2e EF = CO_2 EF x 1 lb-CO2e/lb-CO_2
CO2e EF = 0.418 lb CO_2/lb sorbent used x 1 lb-CO2e/lb-CO_2

CO2e EF = 0.418 lb CO2e/lb sorbent used

Converting this emission factor to metric tons of CO2e emitted per short ton of sorbent used can be performed as follows:

CO2e EF = 0.418 lb CO2e/lb sorbent x (1 short ton CO2e / 2,000 lb CO2e)
x (0.9072 metric ton CO2e/short ton CO2e)
x (2,000 lb sorbent/short ton sorbent used)

CO2e EF = 0.379 metric tons CO2e/short ton sorbent used

C. Baseline Period Determination and Data

Baseline Period Determination:

In accordance with District Rule 2301, Section 4.5.4, GHG emission reductions are calculated using the consecutive 24 month period immediately prior to the date the emission reduction occurred, or another consecutive 24 month period in the 60 months prior to the date the emission reduction occurred if determined by the APCO as being more representative of normal operations.

The original ERC Banking Project (reference project C-1120248) established the baseline period as the two year (24 month) period of operation dating from the start of the 1st quarter in 2009 to the end of the 4th quarter in 2010. Since the District has already established this 24 month time frame as the correct baseline period for the criteria pollutant emission reductions that have already been evaluated and issued, the same baseline period will be used for this evaluation.

Baseline Period Data:

Petroleum Coke Usage:

Year	**Petroleum Coke Usage (short tons/year)**
1 (1st qtr 2009 to 4th qtr 2009)	83,734
2 (1st qtr 2010 to 4th qtr 2010)	70,587

Natural Gas Usage:

Year	**Natural Gas Usage (MMBtu/Year)**
1 (1st qtr 2009 to 4th qtr 2009)	655
2 (1st qtr 2010 to 4th qtr 2010)	2,844

Sorbent Usage:

Year	Sorbent Usage (short tons/Year)
1 (1st qtr 2009 to 4th qtr 2009)	8,294
2 (1st qtr 2010 to 4th qtr 2010)	17,083

D. Historical Actual Emissions (HAE's)

Petroleum Coke Combustion:

As shown above, a CO2e emission factor of 0.103 metric ton/MMBtu will be used to calculate the HAE's from the combustion of petroleum coke in this fluidized bed combustor. Therefore, the historical actual CO2e emissions can be estimated using this emission factor, the fuel usage rates listed above and the conversion of therms to MMBtu of heat output.

CO2e HAE = 0.10314 metric ton/MMBtu x Petroleum Coke Usage (short ton/year)
x 30.0 (MMBtu/short ton)

Petroleum Coke CO2e HAE				
Year	**Emission Factor** (metric ton/MMBtu)	**Petroleum Coke Usage** (short tons/year)	**Heating Value** (MMBtu/ton)	**CO2e HAE** (metric tons/year)
1	0.10314	83,734	30.0	259,090
2	0.10314	70,893	30.0	219,357
			Average:	239,224

Natural Gas Combustion:

As shown above, a CO2e emission factor of 0.05307 metric ton/MMBtu will be used to calculate the HAE's from the combustion of natural gas used in this fluidized bed combustor. Therefore, the historical actual CO2e emissions can be estimated using this emission factor and the sorbent usage rates listed above.

CO2e HAE = 0.05307 metric ton/MMBtu x Petroleum Coke Usage (ton/year)
x 24.8 (MMBtu/ton)

Natural Gas CO2e HAE			
Year	**Emission Factor** (metric ton/MMBtu)	**Natural Gas Usage** (MMBtu/year)	**CO2e HAE** (metric tons/year)
1	0.05307	655	35
2	0.05307	2,844	151
		Average:	93

Sorbent Usage:

As shown above, a CO2e emission factor of 0.379 metric tons CO2e/short ton sorbent used will be used to calculate the HAE's from the use of sorbent in this fluidized bed combustor. Therefore, the historical actual CO2e emissions can be estimated using this emission factor and the fuel usage rates listed above.

CO2e HAE = 0.379 metric tons CO2e/short ton sorbent used x Sorbent Usage (short ton/year)

Sorbent CO2e HAE			
Year	**Emission Factor** (metric ton/short ton)	**Sorbent Usage** (short ton/year)	**CO2e HAE** (metric tons/year)
1	0.379	8,294	3,143
2	0.379	17,083	6,474
		Average:	4,809

The combined total historical actual greenhouse gas emissions from this unit is shown in the table below:

Total Historical Actual Emissions (HAE)	
Pollutant	Metric Tons CO2e/Year
$CO2e_{Petroleum\ Coke}$	239,224
$CO2e_{Natural\ Gas}$	93
$CO2e_{Sorbent}$	4,809
Total:	244,126

E. Post Project Potential to Emit (PE2)

As discussed above, the subject equipment has been permanently shut down and the PTO's were surrendered to the District. Therefore the PE2 is 0.

F. Emission Reductions Eligible for Banking

The emission reductions potentially[1] eligible for banking are the difference between the historical actual emissions and the potential to emit after the project.

ERCs potentially eligible for banking = 244,126 metric ton/year – 0 ton/year
= 244,126 metric ton/year

VI. Compliance:

Rule 2301 - Emission Reduction Credit Banking

Section 4.0 - Eligibility of Emission Reductions

Per Section 4.5, the following criteria shall be met in order to deem GHG emission reductions eligible for banking:

Section 4.5.1 requires that the emission reductions must have occurred after January 1, 2005.

The emission reductions occurred when the fluidized bed combustor and electrical generation equipment was permanently shutdown on August 22, 2011. As these emission reductions occurred after January 1, 2005, this criteria has been satisfied.

Section 4.5.2 requires that the emissions must have occurred in the District.

The emissions occurred at 10596 Idaho Avenue in Hanford, CA. Since this location is in Kings County, which is located within the San Joaquin Valley Air Pollution Control District boundaries, this criteria has been satisfied.

Section 4.5.3 requires that the emission reductions must be real, surplus, permanent, quantifiable, and enforceable.

Real:

The GHG emission reductions were generated by the shutdown of one 320 MMBtu/hr petroleum coke or natural gas fired fluidized bed combustor powering a steam turbine and an associated 30 MW electrical generator. The GHG emission reductions were calculated from actual historic fuel-use data and recognized emission factors. These pieces of equipment have been removed from service and their permits subsequently were surrendered to the District. Therefore, the emission reductions are real.

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[1] See further discussion on necessary adjustments to emission reduction values eligible for banking in section VI below.

Surplus:

The GHG emission reduction occurred when the facility ceased operation in August 2011. In 2013, CARB established a list of entities covered by the cap and trade regulation (based on 2012 actual emissions). Because the facility ceased their electrical generation operations prior to 2012 it is not a covered entity subject to the cap and trade regulation, see a list of covered entities at http://www.arb.ca.gov/cc/capandtrade/covered_entities_110413.xlsx.

Please note that if the facility was still in operation as of 2012 it most likely would have been a covered entity as the actual emissions would have likely exceeded the 25,000 metric ton/year threshold for "large industrial facilities".

It is important to note that even for facilities that are listed as covered entities as part of the cap and trade regulations, GHG emission reductions that occurred prior to Jan 1, 2012 are surplus of the requirements of Rule 2301.

Notwithstanding the above, the emission reductions at this facility occurred in August of 2011. Therefore the emission reduction satisfies the surplusing requirements of section 4.5.3.1.

There are no laws, rules, regulations, agreements, orders, or permits requiring any GHG emission reductions from petroleum coke fired electrical power generation facilities. Therefore, the emission reductions satisfy the surplus requirement in Section 4.5.3.2.

In addition, the emission reductions are not the result of an action taken by the permittee to comply with any requirement. The emission reductions are surplus and additional of all requirements. Therefore, the emission reductions satisfy the surplus requirement in section 4.5.3.4.

The ERC Certificate will be identified according to Section 6.15.3 below.

Permanent:

The 320 MMBtu/hr petroleum coke or natural gas fired fluidized bed combustor driving an electrical generator has been shut down, removed from the facility, and the PTO has been surrendered to the District.

When determining the geographical boundary in which the emission reduction is determined to be permanent the applicant may consider how the GHG ERC may likely be used.

Please note that the while Rule 2301 allows facilities to receive ERCs for GHG emission reductions, the District does not have any requirements on the use of GHG ERCs. However, it is anticipated that the likely uses of such GHG ERCs would be their future retirement as GHG mitigation in the CEQA process.

Pursuant to CEQA, lead agencies must consider the environmental impact of GHG emissions from a project and may require that such GHG emissions be mitigated. In evaluating various mitigation techniques, including the retirement of GHG ERCs, the lead agency must determine if the proposed mitigation technique adequately mitigates the projects GHG emission increase.

When a lead agency determines if the retirement of a particular GHG ERC provides adequate GHG mitigation for a project, the lead agency may choose to consider the location where the GHG ERC was generated and the geographical boundary used to determine the permanence of the emission reduction. In making this determination, the lead agency may conclude that the retirement of a particular GHG ERC would provide adequate mitigation for projects within that same geographical boundary. Again, that determination will be made by the lead agency for a particular project.

This facility has selected the boundaries of the State of California as the geographical boundary for which these emission reductions are permanent. The demand for power within the State of California will not change as a result of this Hanford LP facility shutting down. Therefore, the amount of power that was previously produced by the Hanford LP plant will now need to be picked up and produced by the other power plants in California. Greenhouse gases will be generated from those other power plants in California while picking up the additional power load left behind from the shutdown of the Hanford LP facility. Therefore, the only portion of the historical actual GHG emissions calculated above that are real reductions is the difference from the historical actual GHG emissions from the Hanford LP facility and the future potential GHG emissions generated from the other power plants in California picking up the additional load left behind from the shutdown of the Hanford LP facility.

Potential Load Picked up in California:

Based on Hanford LP's power purchase agreement (PPA) with Pacific Gas and Electric Company (PG&E), the facility would be paid for the sale of up to 23 MW of energy and capacity from the 30 MW petroleum coke fired small power production facility (see copy of pages containing specific terms on selling of Hanford LP's power on the grid in their power purchase agreement with PG&E in Attachment E). The facility also had the ability to generate up to 2 MW of additional energy which the seller could have made available for sale to PG&E. Therefore, in accordance with the PPA, the maximum amount of power that would have been purchased by PG&E from this facility during any given hour was 25 MW. Therefore, for the purposes of this project, the maximum load picked up by other power production facilities in California will be set at 25 MW. Using a worst case operating scenario of 8,760 hours per year, the potential power production load picked up by the other power plants in California will be as follows:

Potential Load = Maximum Load 25 (MW) x Operation (hr/year)
Potential Load = Maximum Load 25 (MW) x 8,760 (hr/year)

Potential Annual Load = 219,000 MWh/year

GHG Emission Factor from Load Picked up in California:

The greenhouse gas emissions from electricity production from power plants located within California can be calculated using District Policy FYI 311 (see Attachment F), which also references a California Energy Commission document titled "Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report", dated October 15, 2007. This document provides an estimate of GHG emissions due to electricity consumption in California as a result of implementing various strategies to reduce GHG emissions in the State by 2020. As specified within this document, the GHG emissions due to electricity consumption can be defined as being the same as the amount of GHG emissions generated for each MWh produced within the State of California. Therefore, this emission factor can be used to estimate the GHG emissions from the electric generation load picked up by the other power plants in California resulting from the shutdown of the Hanford LP facility.
GHG Emission Factor (kg) = 313 kg $CO2e$/MWh

Converting this emission factor from kilograms to metric tons can be performed as follows:

GHG EF (mt) = GHG EF x 1 metric ton/1,000 kg
GHG EF (mt) = 313 kg $CO2e$/MWh x 0.001 metric ton/kg

GHG Emission Factor (mt) = 0.313 metric tons $CO2e$/MWh

Potential GHG Emissions from Load Picked up in California:

Load GHG PE = Potential Annual Load (MWh/year) x GHG EF (metric tons $CO2e$/MWh)

Load GHG PE = 219,000 MWh/year x 0.313 metric tons $CO2e$/MWh

Load GHG PE = 68,547 metric tons $CO2e$/year

Adjustment to ERC's Eligible for Banking:

Adjusting the historical actual GHG emissions eligible for banking from the Hanford LP facility above by the potential future GHG emissions from other power plants in California picking up the additional power load can be performed as follows:

Adjusted GHG ERC's Eligible for Banking = Historical Actual GHG (metric tons/year) – Potential GHG Emissions Produced in California (metric tons/year)

Adjusted GHG ERC's Eligible for Banking = 244,126 metric tons/year – 68,547 metric tons/year

Adjusted GHG ERC's Eligible for Banking = 175,579 metric tons CO2e/year

This ERC evaluation has adjusted the historical actual GHG emissions resulting from the shutdown of the Hanford LP facility by taking in to account the potential GHG emissions resulting from the power plants within the State of California picking up the additional power production load left behind from the shutdown of this facility. The potential GHG emissions were calculated using published GHG emission factor data from electricity production by power plants in California. Therefore, the adjusted GHG emission value to be banked as a result of this project can be considered permanent.

In order to assure continued compliance with the methodology used in this GHG ERC banking evaluation, the ERC certificate will include the following identifier:

"Shutdown of one 320 MMBtu/hr petroleum coke/natural gas fired fluidized bed combustor, verified as permanent within the boundaries of the State of California"

Quantifiable:

The actual emissions were calculated from historic fuel-use records and accepted emission factors. Therefore, the emission reductions are quantifiable and have been quantified.

Enforceable:

The 320 MMBtu/hr fluidized bed combustor driving an electric generator has been shut down and the PTO has been surrendered to the District. Operation of the equipment without a valid permit would subject the permittee to enforcement action.

In addition, section 4.5.4 requires that GHG emission reductions be calculated as the difference between the historic annual average GHG emissions (as CO_2e) and the PE2 after the reduction is complete. The historical GHG emissions must be calculated using the consecutive 24 month period immediately prior to the date the emission reductions occurred (the shutdown of the fluidized bed combustor), or another consecutive 24 month period in the 60 months prior to the date the emission reduction occurred if determined by the APCO as being more representative of normal operations.

The historical actual GHG emission reductions were calculated according to the baseline period identified above and accepted emission factors. Since this is a permanent shutdown of the electrical generation operations and its associated equipment at this facility, there is no post-project potential to emit. Furthermore, the historical actual GHG emissions from this facility have been adjusted to account for the future GHG emissions that will occur due to the other power plants within the boundaries of the State of California picking up the power production load left behind by the shutdown of this facility. Therefore, the emission reductions are enforceable.

Section 4.5.5.5 requires that GHG emission reductions proposed to be quantified using CARB-approved emission reduction project protocols shall be calculated in accordance with the applicable protocol.

Since the GHG emission reductions are not subject to an applicable CARB-approved emission reduction project protocol, this section is not applicable.

Section 4.5.6 requires that ERCs shall be made enforceable through permit conditions or legally binding contract.

The 320 MMBtu/hr fluidized bed combustor used for electrical power generation held a legal District operating permit. That permit has since been surrendered to the District. Since the operation of the equipment would require a new Authority to Construct, as discussed above, the emission reduction is enforceable.

Section 5.0 - ERC Application Procedures

Section 5.5.2 requires, for emission reductions occurring prior to January 1, 2012, applications for ERCs must be submitted by July 19, 2012.

The ERC application was submitted on January 31, 2012, therefore the application was submitted in a timely fashion.

Section 6.0 - Registration of ERC Certificates

The APCO may only grant an ERC Certificate after the emission reductions have actually occurred upon satisfaction of the following applicable provisions:

6.14 Greenhouse gas emission reductions shall be banked as metric tons of CO2E per year, rounded to the nearest metric ton.

The draft ERCs are identified as metric tons of CO2e per year, rounded to the nearest metric ton.

Section 6.15 specifies the registration requirements for GHG ERCs.

These emission reductions are surplus and additional of all requirements pursuant to Section 4.5.3.4. Therefore the ERC certificate shall include the following notation:

"This emission reduction is surplus and additional to all applicable regulatory requirements."

Compliance with Rule 2301 has been demonstrated and no adjustments are required under this Rule.

VII. Recommendation:

Pending a successful Public Noticing period, issue Emission Reduction Credit certificate and C-1282-24 (CO_2e) to Hanford LP in accordance with the amounts specified on the draft ERC certificates in Attachment G.

Attachments:

Attachment A,	Surrendered PTO C-603-1-11
Attachment B,	ERC Application
Attachment C,	Hanford LP Petroleum Coke, Natural Gas and Sorbent Usage Records
Attachment D,	40 CFR Part 98 GHG Emission Factors and Global Warming Potentials (GWP): Tables A-1, C-1 and C-2
Attachment E,	Hanford LP Power Purchase Agreement with PG&E
Attachment F,	District Policy FYI 311
Attachment G,	Draft ERC Certificate C-1282-24

Attachment A

Surrendered PTO C-603-1-11

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-603-1-11 **EXPIRATION DATE:** 04/30/2008

EQUIPMENT DESCRIPTION:
30 MW FLUIDIZED BED COMBUSTOR FUELED BY PETROLEUM COKE, NATURAL GAS, AND NO. 2 FUEL OIL UP TO 320 MMBTU/HR

PERMIT UNIT REQUIREMENTS

1. Fuel consumption in the fluidized bed combustor shall not exceed 320 MMBTU/hr of petroleum coke, natural gas, and No. 2 fuel oil. [District Rule 2201] Federally Enforceable Through Title V Permit
2. Natural gas utilization in the fluidized bed combustor shall not exceed 48 MMBTU/hr. Fuel oil may only be used during warm-up or as necessary to establish or maintain bed temperature at 1,560 degree F at a rate not to exceed 170 MMBTU/hr. [District Rule 2201] Federally Enforceable Through Title V Permit
3. Natural gas consumption in the low pressure evaporator shall not exceed 2 million scf in any one day. [District Rule 2201] Federally Enforceable Through Title V Permit
4. The NOx emissions (measured as NO_2) from the combined exhaust of the low pressure evaporator and fluidized bed combustor shall not exceed 245 pounds in any one day. [District Rule 2201] Federally Enforceable Through Title V Permit
5. The NOx concentration (as NO_2 corrected to 3% O_2) in the combined exhaust of the fluidized bed combustor and low pressure evaporator shall not exceed 28 ppmvd averaged over any 3 hour period when the freeboard temperature is at least 1,560 degree F. [District Rules 2201, District Rule 4301 and District Rule 4352, 5.1] Federally Enforceable Through Title V Permit
6. The carbon monoxide emissions from the combined exhaust of the fluidized bed combustor and low pressure evaporator shall not exceed 544 pounds in any one day. [District Rule 2201 and District Rule 4352, 5.3] Federally Enforceable Through Title V Permit
7. Annual carbon monoxide emissions from the combined exhaust of the fluidized bed combustor and low pressure evaporator shall not exceed 156,000 pounds per year. [District Rule 2201] Federally Enforceable Through Title V Permit
8. The VOC emissions from the combined exhaust of the fluidized bed combustor and low pressure evaporator shall not exceed 60 pounds in any one day. [District Rule 2201] Federally Enforceable Through Title V Permit
9. The PM10 emissions from the combined exhaust of the fluidized bed combustor and low pressure evaporator shall not exceed 80 pounds in any one day. [District Rule 2201] Federally Enforceable Through Title V Permit
10. The concentration of particulate matter in the exhaust from the main baghouse shall not exceed 0.005 gr/dscf corrected to 12% CO_2. [District Rule 2201, District Rule 4301, and 40 CFR 60.43b(c)] Federally Enforceable Through Title V Permit
11. SOx emissions (calculated as SO_2) from the combined exhaust of the combustor and the low pressure evaporator shall not exceed 469 pounds per day. [District Rule 2201] Federally Enforceable Through Title V Permit
12. Sorbent shall be injected into the fluidized bed combustor at a rate sufficient to meet the SOx concentration and emissions limits in these conditions. [District Rule 2201] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

13. The SOx concentration (as SO2 corrected to 3% O2) in the combined exhaust of the fluidized bed combustor and low pressure evaporator shall not exceed 35 ppmvd averaged over any three hour period when the bed temperature was at least 1,500 degree F. [District Rule 2201, District Rule 4301and District Rule 4801] Federally Enforceable Through Title V Permit

14. A start-up event commences when the petroleum coke feed to the CFBC is initiated and/or the freeboard temperature is 1,560 degree F. The start-up event is complete when the NOx concentration and SOx concentration are in compliance with the concentration limits. A shutdown event commences when the petroleum coke feed to the CFBC is terminated and is complete when the combustion air flow to the CFBC is terminated. [District Rule 2201] Federally Enforceable Through Title V Permit

15. The start-up/shutdown event shall not exceed any of the following limits: 2 hours, 1 per day, 50 per year. [District Rule 2201] Federally Enforceable Through Title V Permit

16. Emissions from the circulating fluidized bed combustor shall not exceed either of the following limits during a start-up or shutdown event: 140 lb NOx/hr or 200 lb SO2/hr. [District Rule 2201] Federally Enforceable Through Title V Permit

17. In no event shall SO2 emissions from the combined exhaust of the combustor and the low pressure evaporator exceed 76.1 ton/yr. [District Rule 2201 and 40 CFR 52.21] Federally Enforceable Through Title V Permit

18. Ammonia shall be injected into the fluidized bed combustor as necessary to meet the limits in these conditions and whenever the freeboard temperature is at least 1,560 degree F. [District Rule 2201] Federally Enforceable Through Title V Permit

19. The concentration of ammonia in the combined exhaust of the fluidized bed combustor and low pressure evaporator shall not exceed 30 ppmvd. [District Rule 2201] Federally Enforceable Through Title V Permit

20. Source testing to demonstrate compliance with permit conditions and all rules and regulations shall be conducted on an annual basis. [District Rule 1081] Federally Enforceable Through Title V Permit

21. Performance testing shall be conducted annually for NOx, CO, SOx, and PM(10) at normal operating capacity using following test methods; for NOx, EPA Method 7E or ARB Method 1-100; for CO, EPA Method 10 or ARB Method 100; for SOx, EPA Method 6 or 6C ; and for PM(10), EPA Method 201A, and SCAQMD Method 5.3 and 6.1. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

22. Filterable PM(10) shall be quantified using EPA Method 201A. Condensable PM10 from the back-half of the test apparatus shall be quantified using SCAQMD methods 5.3 and 6.1. Total PM10 is the sum of the results of these two tests. [District Rules 1081 and 2201] Federally Enforceable Through Title V Permit

23. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

24. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

25. The pressure drop across the filter fabric in the combustion exhaust baghouse shall be monitored daily. Immediate corrective action must be taken if the pressure drop in any section is greater than 10 inches H2O or less than 0.5 inches H2O. [District Rule 2201] Federally Enforceable Through Title V Permit

26. A Continuous Emissions Monitoring System shall be in place and operating whenever the facility is operating. NOx (as NO2 corrected to 3% O2), SOx as SO2, CO, opacity and O2 concentrations must be recorded continuously. [District Rule 1080] Federally Enforceable Through Title V Permit

27. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080] Federally Enforceable Through Title V Permit

28. The continuous monitoring equipment must be linked to a data logger which is compatible with the District's data acquisition system. [District Rule 1080 and District Rule 4352] Federally Enforceable Through Title V Permit

29. The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] Federally Enforceable Through Title V Permit

30. Operator shall notify the APCO no later than eight hours after the detection of a breakdown of the CEMS. Operator shall inform the APCO of the intent to shut down the CEMS at least 24 hours prior to the event. [District Rule 1080; Fresno County Rule 108] Federally Enforceable Through Title V Permit

31. The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080, 40 CFR 60.49b(f) and 40 CFR 60.49b(h)] Federally Enforceable Through Title V Permit

32. An ultimate analysis for each lot of liquid or solid fuel received shall be maintained on site and made available to the District upon request. The analyses shall include heating value, sulfur content, and nitrogen content. [District Rule 1070] Federally Enforceable Through Title V Permit

33. Records of all daily fuel consumption shall be maintained on site and submitted to the District with quarterly reports and upon request. [District Rule 1070, District rule 1080, District Rule 4352 and 40 CFR 60.49b(d)] Federally Enforceable Through Title V Permit

34. A violation of NOx emission standards indicated by the NOx CEM shall be reported by the operator to the APCO within 96 hours. [Rule 108 (Kings, Fresno, Merced San Joaquin, Tulare, Kern, and Stanislaus) and Rule 109 (Madera) and District Rule 1080, 9.0] Federally Enforceable Through Title V Permit

35. If the unit is fired on diesel fuel that is not supplier-certified 0.0015% sulfur content or less, the sulfur content of each fuel source shall be tested weekly, except that if compliance with the fuel sulfur content limit has been demonstrated for 8 consecutive weeks for a fuel source, then the testing frequency shall be semi-annually. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

36. Operator shall maintain copies of fuel invoices and supplier certifications. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

37. Records of system maintenance, inspections, and repair shall be maintained. The records shall include identification of the equipment, date of inspection, corrective action taken, and identification of the individual performing the inspection. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

38. Operator shall maintain all records for at least five years and conform to the recordkeeping requirements described in District Rule 2520. [District Rule 2520, 9.4.2] Federally Enforceable Through Title V Permit

Attachment B

ERC Application

/

San Joaquin Valley Air Pollution Control District

RECEIVED
JAN 31 2012
Permits Services
SJVAPCD

Application for

[X] EMISSION REDUCTION CREDIT (ERC) [ ] CONSOLIDATION OF ERC CERTIFICATES

1. ERC TO BE ISSUED TO: Hanford LP — Facility ID: C- 603 (if known)

2. MAILING ADDRESS: Street/P.O. Box: 4300 Railroad Avenue

City: Pittsburg State: CA Zip Code: 94565-6006

3. LOCATION OF REDUCTION:
Street: ___10596 Idaho Avenue

City: _Hanford, CA, 93230

The Site Universal Transverse Mercator (UTM) coordinates are at Zone 11, Horizontal 262,139.0 meters, Vertical 4,016,882.0 meters. The plant is at 36^0 16' 9'' North Latitude and 119^0 38' 52'' West Longitude.

_______/4 SECTION _________ TOWNSHIP _________ RANGE _________

4. DATE OF REDUCTION:
August 22, 2011

5. PERMIT NO(S): C-603-1-6 EXISTING ERC NO(S):

6. METHOD RESULTING IN EMISSION REDUCTION:

[X] SHUTDOWN [ ] RETROFIT [ ] PROCESS CHANGE [ ] OTHER

DESCRIPTION: 30 MW Fluidized Bed Combustor fueled by Petroleum Coke, Natural Gas and No. 2 Fuel oil up to 320 MMBTU/hr was shutdown on August 22, 2011 and all permits have been designated dormant.

(Use additional sheets if necessary)

7. REQUESTED ERCs (In Metric Tons Per Calendar Quarter):

	VOC	NOx	CO	PM10	SOx	OTHER
1ST QUARTER						59629
2ND QUARTER						59629
3RD QUARTER						59630
4TH QUARTER						59629

Note: Other is for Greenhouse Gases (GHG)

8. SIGNATURE OF APPLICANT:

TYPE OR PRINT TITLE OF APPLICANT:
Vice President

9. TYPE OR PRINT NAME OF APPLICANT: Douglas W. Wheeler

DATE: 01/12/2012

TELEPHONE NO: 925.431.1443

FOR APCD USE ONLY:

DATE STAMP

FILING FEE
RECEIVED: $ __________/__________

DATE PAID:

PROJECT NO.: C-1120606 FACILITY ID.: C-603

GWF
GWF POWER SYSTEMS

RECEIVED
JAN 31 2012
Permits Services
SJVAPCD

January 26, 2012

Mr. Jim Swaney
San Joaquin Valley Air Pollution Control District
Permit Services Manager, Central Region
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244

Re: Hanford LP Emission Reduction Credit Applications

Dear Mr. Swaney

The Hanford LP petroleum coke fueled electrical generating plant (SJVAPCD Facility C-603) was shut down on August 22, 2011 when the Power Purchase Agreement with PG&E expired. The plant is a 30 MW, 320 MMBtu/hr Fluidized Bed Combustor fueled with petroleum coke and using natural gas and No. 2 Fuel oil for start up. We have prepared and are submitting three separate application forms: (1) Requesting the banking of NOx, SO2, VOC, PM-10 and CO emission reductions consistent with San Joaquin Valley Air Pollution Control District ("District") Rule 2301; (2) Requesting the banking of PM-10 emissions from the cooling tower in accordance with Rule 2301; and (3) Requesting the banking of GHG emission reductions consistent with proposed amendments to Rule 2301 that will be considered by the District Board this month. We recognize that the District may postpone review of the GHG banking application until the District Board approves the proposed amendments to Rule 2301, which are scheduled for consideration on January 19, 2012.

Hanford LP is submitting the attached three applications to bank as Emission Reduction Credits the actual emissions reductions that resulted from the August 22, 2011 facility shutdown. The first application covers emissions of NOx, SO2, VOC, PM-10 and CO from the combustor, the second application covers the PM-10 from the cooling tower, and the third application covers the GHG emission reductions that we are requesting be banked once the Board has approved the proposed amendments to Rule 2301.

A plot plan of the facility is included as Attachment 1. The plot plan identifies the location of the permit units which have been shut-down and are as follows::

- ☐ C-603-1-6 Fluidized Bed Combustor

4300 RAILROAD AVE., PITTSBURG, CALIFORNIA 94565 • TEL. (925) 431-1444 • FAX (925) 431-0515

- ☐ C-603-3-2 Gypsum Silo and Bin Vent Filter
- ☐ C-603-2-2 Kaolin Silo and Bin Vent Filter
- ☐ C-603-13-4 Synthetic Gypsum (Fly Ash) Silo and Bin Vent Filter
- ☐ C-603-14-2 Synthetic Gypsum (Bed Ash) Silo and Bin Vent Filter
- ☐ C-603-15-2 Sodium Bicarbonate Silo and Bin Vent Filter
- ☐ C-603-16-1 Cooling Tower

You will note that C-603-6-3 Emergency Generator is not included, as the generator will continue to operate as part of the GWF Energy LLC Hanford Peaker Plant.

Throughout most of Hanford LP's operating history, petroleum coke was supplied from the Bakersfield refinery. The refinery changed ownership several times over the plant's history, starting with Texaco, Shell and finally Flying "J". Hanford LP received notice from Flying "J" that the Bakersfield refinery was shutting down and although the refinery has been sold, remains shutdown. As a result of the Bakersfield refinery shutdown, Hanford LP began using petroleum coke from the Conoco-Philips refinery in Santa Maria and the Shell refinery in Martinez. The petroleum coke was blended to optimize the sulfur content and the delivered coke price. Because the emissions from Hanford LP directly relate to the amount of petroleum coke utilized by the facility, Attachment 2 summarizes the petroleum coke utilized by month over the five-year period prior to the August 22, 2011 shutdown. The two-year period Hanford LP proposes that best reflects the operations and emissions profile of the facility is the period beginning January, 2009 and ending December, 2010.

A summary of the calculation methodologies for NOx, SO2, CO, PM-10 and VOC is included as Attachment 3. The calculations of emission reductions for NOx, SO2, and CO are based on the CEMS stack monitoring data, that by permit condition has been reported to the District on a monthly basis over the operating history of the plant and is included as Attachment 4. Attached as Exhibit 1 is a summary of the NOx, SO2, and CO CEMs data for the proposed period. The calculations for PM-10 and VOC emissions are based on annual source test results. A summary of those calculated emissions is included as Attachment 5. The source test results for the proposed period are attached as Exhibit 2 .

The application for banking the GHG emissions reduction provides GHG emissions by quarter as CO2E, including the CO2E for CO2, CH4, and N2O expressed in metric tons. The two year period proposed is the same period as that used for the requested emission reductions for NOx, SO2, CO, PM-10, and VOC. Although the reporting period under ARB's Mandatory Reporting Rule for GHGs is different from the period proposed for this banking application, the emission factors for CO2, CH4, and N20 are the same as those approved by EPA and ARB and are calculated based on the petroleum coke and natural gas burned as well as on the quantity of limestone used for SO2 control. The calculation methodology and calculated emissions are summarized by month for the proposed period. The calculated GHG emissions are summarized as CO2E in Attachment 6.

A separate application has been prepared for the PM-10 emissions from the cooling tower. We are proposing the same two year baseline period even though the cooling tower PM-10 emissions are not impacted by the capacity factor. That is to say, when the plant is being operated at a reduced capacity factor, the cooling tower circulation rate and the resulting PM-10 emissions do not change. The main variable that affects the PM-10 emissions is the TDS in the cooling tower water. Attachment 7 summarizes the TDS and hours of operation by month for the proposed baseline period.

If you have any questions, please contact me at 925-431-1443

Thank you for consideration in this matter

Sincerely,

D.W.Wheeler

Vice-President

Attachment C

320 MMBtu/hr Fluidized Bed Combustor Petroleum Coke, Natural Gas, and Sorbent Usage Records

ATTACHMENT 2

Petroleum Coke Usage

Hanford LP
Permit No. C-603-1-6

Date/Month	Coke Usage Tons	Date/Month	Coke Usage Tons	Date/Month	Coke Usage Tons
Jan-06	7,224	Jan-08	7,137	Jan-10	6,909
Feb-06	6,795	Feb-08	6,614	Feb-10	4,731
Mar-06	7,438	Mar-08	4,762	Mar-10	7,054
Apr-06	7,459	Apr-08	7,037	Apr-10	7,057
May-06	7,292	May-08	7,278	May-10	7,284
Jun-06	7,129	Jun-08	6,893	Jun-10	6,752
Jul-06	7,472	Jul-08	7,378	Jul-10	6,074
Aug-06	7,484	Aug-08	7,240	Aug-10	6,397
Sep-06	7,030	Sep-08	7,067	Sep-10	4,734
Oct-06	4,781	Oct-08	6,221	Oct-10	4,479
Nov-06	6,404	Nov-08	7,035	Nov-10	6,745
Dec-06	7,741	Dec-08	7,500	Dec-10	2,407
Jan-07	7,637	Jan-09	7,097	Jan-11	3,052
Feb-07	6,650	Feb-09	6,534	Feb-11	5,647
Mar-07	7,066	Mar-09	7,308	Mar-11	5,806
Apr-07	7,013	Apr-09	7,041	Apr-11	4,133
May-07	7,451	May-09	7,284	May-11	3,177
Jun-07	7,288	Jun-09	5,777	Jun-11	4,830
Jul-07	7,587	Jul-09	7,215	Jul-11	6,471
Aug-07	7,560	Aug-09	7,157	Aug-11	4,851
Sep-07	7,168	Sep-09	6,436	--------	--------
Oct-07	7,517	Oct-09	7,606	--------	--------
Nov-07	7,353	Nov-09	7,068	--------	--------
Dec-07	7,235	Dec-09	7,211	--------	--------

ATTACHMENT 6

GREENHOUSE GASES (GHG)

Hanford LP
Permit No. C-603-1-6

	Coke Usage Tons	Sorbent Usage Tons	Nat Gas Usage MMBTU	Coke Carbon Content %	Coke CO2 MT	Total Carbonate Usage (Sorbent) Tons	Sorbent CO2 MT	Nat Gas CO2 MT	$CO2_e$ from Coke CH4 MT	$CO2_e$ from Nat Gas CH4 MT	$CO2_e$ from Coke N_2O MT	$CO2_e$ from Nat Gas N_2O MT	Total $CO2_e$ MT
Jan-09	7,750	671	0	86.5	22,286	637	254.26	0.00	12.11	0.0000	35.75	0.0000	22,588.34
Feb-09	6,997	513	0	86.4	20,091	487	194.53	0.00	10.93	0.0000	32.28	0.0000	20,328.96
Mar-09	7,963	647	0	85.3	22,566	614	245.20	0.00	12.44	0.0000	36.73	0.0000	22,860.01
Apr-09	7,686	632	0	87.0	22,230	601	239.81	0.00	12.01	0.0000	35.45	0.0000	22,517.15
May-09	8,152	561	0	83.5	22,633	533	212.85	0.00	12.74	0.0000	37.60	0.0000	22,896.44
Jun-09	6,490	547	300	83.9	18,098	520	207.54	15.86	10.14	0.0057	29.94	0.0837	18,361.43
Jul-09	7864	613	0	87.6	22,891	583	232.53	0.00	12.29	0.0000	36.28	0.0000	23,172.25
Aug-09	7798	648	0	83.2	21,559	616	245.77	0.00	12.18	0.0000	35.97	0.0000	21,852.74
Sep-09	7109	825	355	87.8	20,738	783	312.70	18.77	11.11	0.0067	32.79	0.0990	21,113.24
Oct-09	8269	1131	0	83.7	23,004	1,074	428.85	0.00	12.92	0.0000	38.14	0.0000	23,483.80
Nov-09	7560	777	0	84.0	21,110	738	294.65	0.00	11.81	0.0000	34.87	0.0000	21,451.51
Dec-09	7927	729	0	80.9	21,326	692	276.41	0.00	12.39	0.0000	36.57	0.0000	21,651.00
Jan-10	7439	1161	0	80.2	19,839	1,103	440.33	0.00	11.62	0.0000	34.31	0.0000	20,325.06
Feb-10	5335	772	784	80.5	14,281	733	292.59	41.45	8.34	0.0148	24.61	0.2187	14,648.60
Mar-10	7796	1099	0	79.6	20,637	1,044	416.93	0.00	12.18	0.0000	35.96	0.0000	21,101.92
Apr-10	7955	1795	0	78.9	20,873	1,706	680.78	0.00	12.43	0.0000	36.69	0.0000	21,602.83
May-10	8145	1719	0	79.8	21,616	1,633	651.93	0.00	12.73	0.0000	37.57	0.0000	22,318.50
Jun-10	7472	1791	0	78.9	19,608	1,701	679.12	0.00	11.67	0.0000	34.47	0.0000	20,332.91
Jul-10	6914	1871	0	80.5	18,506	1,778	709.60	0.00	10.80	0.0000	31.89	0.0000	19,258.28
Aug-10	7154	1858	275	79.7	18,960	1,765	704.46	14.54	11.18	0.0052	33.00	0.0767	19,722.82
Sep-10	5329	1318	940	82.7	14,653	1,252	499.80	49.70	8.33	0.0178	24.58	0.2623	15,236.00
Oct-10	4974	1183	845	77.6	12,832	1,124	448.53	44.68	7.77	0.0160	22.94	0.2358	13,355.78
Nov-10	7519	1843	0	76.5	19,112	1,751	698.96	0.00	11.75	0.0000	34.68	0.0000	19,857.66
Dec-10	2684	673	0	75.4	6,725	639	255.25	0.00	4.19	0.0000	12.38	0.0000	6,997.05

Annual Average:
(Based on Two Years) **238,517**

Natural Gas CO2 Emission Factor	*52.87*	kg/MMBtu
Calcium Carbonate CO2 Emission Factor	*0.44*	MT/MT
Petroleum Coke Default CH4 Emission Factor	*3.0*	*g/MMBtu*
Natural Gas CH4 Emission Factor	*0.9*	*g/MMBtu*
Diesel CH4 Emission Factor	*0.0*	
Petroleum Coke Default N2O Emission Factor	*0.6*	*g/MMBtu*
Natural Gas Default N2O Emission Factor	*0.1*	*g/MMBtu*
Diesel N2O Default Emission Factor	*0.0*	
Petroleum Coke Default Higher Heating Value	*24.8*	*MMBtu/ton*

Formulas

Coke CO2 (MT)=	(Coke Usage tons)*0.9072*(Coke carbon content%/100)*3.664
Sorbent CO2 (MT)=	(Calcium Carbonate Usage*0.44)*0.9072 < MT conversion
Nat Gas CO2 (MT)=	(Natural Gas Usage*52.87)/1000
$CO2_e$ from Coke CH4=	(((Coke Usage tons)*(Petroleum Coke default CH4 Emission Factor)*(Petroleum Coke default Higher Heating Value))/1000000)))*CH4 Global Warming Potential Factor
$CO2_e$ from Nat Gas CH4=	(((Nat Gas Usage tons)*(Nat Gas default CH4 Emission Factor))/1000000)))*CH4 Global Warming Potential Factor
$CO2_e$ from Coke N_2O=	(((Coke Usage tons)*(Petroleum Coke default N2O Emission Factor)*(Petroleum Coke default Higher Heating Value))/1000000)))*N2O Global Warming Potential Factor
$CO2_e$ from Nat Gas N_2O=	(((Nat Gas Usage tons)*(Nat Gas default N2O Emission Factor))/1000000)))*N2O Global Warming Potential Factor

Global Warming Potentials (GWP)	
CO2	1
CH4	21
N2O	310

Attachment D

40 CFR Part 98 GHG Emission Factors and Global Warming Potentials (GWP): Tables A-1, C-1 and C-2

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of February 28, 2014

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart A—General Provision

TABLE A-1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

GLOBAL WARMING POTENTIALS

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124-38-9	CO_2	1
Methane	74-82-8	CH_4	[a]25
Nitrous oxide	10024-97-2	N_2O	[a]298
HFC-23	75-46-7	CHF_3	[a]14,800
HFC-32	75-10-5	CH_2F_2	[a]675
HFC-41	593-53-3	CH_3F	[a]92
HFC-125	354-33-6	C_2HF_5	[a]3,500
HFC-134	359-35-3	$C_2H_2F_4$	[a]1,100
HFC-134a	811-97-2	CH_2FCF_3	[a]1,430
HFC-143	430-66-0	$C_2H_3F_3$	[a]353
HFC-143a	420-46-2	$C_2H_3F_3$	[a]4,470
HFC-152	624-72-6	CH_2FCH_2F	53
HFC-152a	75-37-6	CH_3CHF_2	[a]124
HFC-161	353-36-6	CH_3CH_2F	12
HFC-227ea	431-89-0	C_3HF_7	[a]3,220
HFC-236cb	677-56-5	$CH_2FCF_2CF_3$	1,340
HFC-236ea	431-63-0	CHF_2CHFCF_3	1,370
HFC-236fa	690-39-1	$C_3H_2F_6$	[a]9,810
HFC-245ca	679-86-7	$C_3H_3F_5$	[a]693
HFC-245fa	460-73-1	$CHF_2CH_2CF_3$	1,030
HFC-365mfc	406-58-6	$CH_3CF_2CH_2CF_3$	794
HFC-43-10mee	138495-42-8	$CF_3CFHCFHCF_2CF_3$	[a]1,640
Sulfur hexafluoride	2551-62-4	SF_6	[a]22,800
Trifluoromethyl sulphur pentafluoride	373-80-8	SF_5CF_3	17,700
Nitrogen trifluoride	7783-54-2	NF_3	17,200

PFC-14 (Perfluoromethane)	75-73-0	CF_4	[a]7,390
PFC-116 (Perfluoroethane)	76-16-4	C_2F_6	[a]12,200
PFC-218 (Perfluoropropane)	76-19-7	C_3F_8	[a]8,830
Perfluorocyclopropane	931-91-9	$C\text{-}C_3F_6$	17,340
PFC-3-1-10 (Perfluorobutane)	355-25-9	C_4F_{10}	[a]8,860
PFC-318 (Perfluorocyclobutane)	115-25-3	$C\text{-}C_4F_8$	[a]10,300
PFC-4-1-12 (Perfluoropentane)	678-26-2	C_5F_{12}	[a]9,160
PFC-5-1-14 (Perfluorohexane, FC-72)	355-42-0	C_6F_{14}	[a]9,300
PFC-9-1-18	306-94-5	$C_{10}F_{18}$	7,500
HCFE-235da2 (Isoflurane)	26675-46-7	$CHF_2OCHClCF_3$	350
HFE-43-10pccc (H-Galden 1040x, HG-11)	E1730133	$CHF_2OCF_2OC_2F_4OCHF_2$	1,870
HFE-125	3822-68-2	CHF_2OCF_3	14,900
HFE-134 (HG-00)	1691-17-4	CHF_2OCHF_2	6,320
HFE-143a	421-14-7	CH_3OCF_3	756
HFE-227ea	2356-62-9	$CF_3CHFOCF_3$	1,540
HFE-236ca12 (HG-10)	78522-47-1	$CHF_2OCF_2OCHF_2$	2,800
HFE-236ea2 (Desflurane)	57041-67-5	$CHF_2OCHFCF_3$	989
HFE-236fa	20193-67-3	$CF_3CH_2OCF_3$	487
HFE-245cb2	22410-44-2	$CH_3OCF_2CF_3$	708
HFE-245fa1	84011-15-4	$CHF_2CH_2OCF_3$	286
HFE-245fa2	1885-48-9	$CHF_2OCH_2CF_3$	659
HFE-254cb2	425-88-7	$CH_3OCF_2CHF_2$	359
HFE-263fb2	460-43-5	$CF_3CH_2OCH_3$	11
HFE-329mcc2	134769-21-4	$CF_3CF_2OCF_2CHF_2$	919
HFE-338mcf2	156053-88-2	$CF_3CF_2OCH_2CF_3$	552
HFE-338pcc13 (HG-01)	188690-78-0	$CHF_2OCF_2CF_2OCHF_2$	1,500
HFE-347mcc3 (HFE-7000)	375-03-1	$CH_3OCF_2CF_2CF_3$	575
HFE-347mcf2	171182-95-9	$CF_3CF_2OCH_2CHF_2$	374
HFE-347pcf2	406-78-0	$CHF_2CF_2OCH_2CF_3$	580
HFE-356mec3	382-34-3	$CH_3OCF_2CHFCF_3$	101
HFE-356pcc3	160620-20-2	$CH_3OCF_2CF_2CHF_2$	110
HFE-356pcf2	50807-77-7	$CHF_2CH_2OCF_2CHF_2$	265
HFE-356pcf3	35042-99-0	$CHF_2OCH_2CF_2CHF_2$	502
HFE-365mcf3	378-16-5	$CF_3CF_2CH_2OCH_3$	11
HFE-374pc2	512-51-6	$CH_3CH_2OCF_2CHF_2$	557
HFE-449s1 (HFE-7100)	163702-07-6	$C_4F_9OCH_3$	297
Chemical blend	163702-08-7	$(CF_3)_2CFCF_2OCH_3$	
HFE-569sf2 (HFE-7200)	163702-05-4	$C_4F_9OC_2H_5$	59
Chemical blend		$(CF_3)_2CFCF_2OC_2H_5$	

	163702-06-5		
Sevoflurane (HFE-347mmz1)	28523-86-6	$CH_2FOCH(CF_3)_2$	345
HFE-356mm1	13171-18-1	$(CF_3)_2CHOCH_3$	27
HFE-338mmz1	26103-08-2	$CHF_2OCH(CF_3)_2$	380
(Octafluorotetramethy-lene) hydroxymethyl group	NA	$X\text{-}(CF_2)_4CH(OH)\text{-}X$	73
HFE-347mmy1	22052-84-2	$CH_3OCF(CF_3)_2$	343
Bis(trifluoromethyl)-methanol	920-66-1	$(CF_3)_2CHOH$	195
2,2,3,3,3-pentafluoropropanol	422-05-9	$CF_3CF_2CH_2OH$	42
PFPMIE (HT-70)	NA	$CF_3OCF(CF_3)$ $CF_2OCF_2OCF_3$	10,300

[a]The GWP for this compound is different than the GWP in the version of Table A-1 to subpart A of part 98 published on October 30, 2009.

[78 FR 71948, Nov. 29, 2013]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of February 28, 2014

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart C—General Stationary Fuel Combustion Sources

TABLE C-1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial sector)	21.39	94.27
Mixed (Industrial coking)	26.28	93.90
Mixed (Industrial sector)	22.35	94.67
Mixed (Electric Power sector)	19.73	95.52
Natural gas	mmBtu/scf	kg CO_2/mmBtu
(Weighted U.S. Average)	1.026×10^{-3}	53.06
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	61.71
Propane[1]	0.091	62.87
Propylene[2]	0.091	67.77
Ethane[1]	0.068	59.60
Ethanol	0.084	68.44
Ethylene[2]	0.058	65.96
Isobutane[1]	0.099	64.94
Isobutylene[1]	0.103	68.86

Butane[1]	0.103	64.77
Butylene[1]	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.54
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Other fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Municipal Solid Waste	9.95[3]	90.7
Tires	28.00	85.97
Plastics	38.00	75.00
Petroleum Coke	30.00	102.41
Other fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas[4]	1.388×10^{-3}	59.00
Biomass fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Wood and Wood Residuals (dry basis)[5]	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Landfill Gas	0.485×10^{-3}	52.07
Other Biomass Gases	0.655×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2/mmBtu
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]The HHV for components of LPG determined at 60 °F and saturation pressure with the exception of ethylene.

[2]Ethylene HHV determined at 41 °F (5 °C) and saturation pressure.

[3]Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input

from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

[4]Reporters subject to subpart X of this part that are complying with §98.243(d) or subpart Y of this part may only use the default HHV and the default CO_2 emission factor for fuel gas combustion under the conditions prescribed in §98.243(d)(2)(i) and (d)(2)(ii) and §98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C-5) or Tier 4.

[5]Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV_w = ((100 - M)/100)*HHV_d$ where HHV_w = wet basis HHV, M = moisture content (percent) and HHV_d = dry basis HHV from Table C-1.

[78 FR 71950, Nov. 29, 2013]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of February 28, 2014

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart C—General Stationary Fuel Combustion Sources

TABLE C-2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Fuel Gas	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Fumace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C-1, except wood and wood residuals)	3.2×10^{-02}	4.2×10^{-03}
Wood and wood residuals	7.2×10^{-03}	3.6×10^{-03}
Biomass Fuels—Gaseous (All fuel types in Table C-1)	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1g of CH_4/mmBtu.

[78 FR 71952, Nov. 29, 2013]

Attachment E

Hanford LP Power Purchase Agreement with PG&E
(only pages specific to terms of selling power on the grid)

(PG&E LOG NO. 25C136)

6th Amendment Hanford LP

Ref

SIXTH AMENDMENT TO THE LONG-TERM ENERGY AND CAPACITY POWER PURCHASE AGREEMENT BETWEEN HANFORD L.P. AND PACIFIC GAS AND ELECTRIC COMPANY

THIS SIXTH AMENDMENT ("Sixth Amendment") to the power purchase agreement described below in Recital A is by and between PACIFIC GAS AND ELECTRIC COMPANY ("PG&E"), a California corporation and HANFORD L.P. ("Seller"), a Delaware limited partnership. PG&E and Seller are sometimes referred to herein individually as "Party" and collectively as the "Parties."

RECITALS

A. Seller and PG&E are Parties to a Long-Term Energy and Capacity Power Purchase Agreement, effective June 26, 1985, amended by amendments one through five (the "PPA"), for the purchase of up to 23,000 kw of energy and capacity from the 25,000 kw petroleum coke-fired small power production facility (PG&E Log No. 25C136) located in Hanford, California (the "Facility"). The PPA will expire on August 22, 2011. The Facility has the ability to generate up to 2,000 kw of additional energy which Seller can make available for sale to PG&E.

B. The Parties agree that it will be to their mutual interest to enter into this Sixth Amendment whereby Seller agrees to sell incremental energy to PG&E.

C. To accommodate sales of incremental energy under the PPA, the Parties hereby agree to the terms and conditions set forth below.

D. The Parties reached agreement in principle on the terms of this Sixth Amendment on or before July 31, 2000; to expedite commencement of incremental energy deliveries, the Parties agree that this Sixth Amendment shall apply to incremental energy deliveries Seller has made since July 31, 2000 at 12:00 p.m.

AGREEMENT

The Parties agree as follows:

1. DEFINITIONS

Whenever used in this Sixth Amendment, the following terms shall have the following meanings:

1.1. Unless otherwise defined below in this section 1, all underlined terms used herein shall have the meanings ascribed to them in APPENDIX A, Section A-1, DEFINITIONS, pages A-2 through A-7 of the PPA as amended.

1.2. Imbalance charge: A dollar per megawatt-hour ($/mwh) charge (or credit) assessed to Seller pursuant to section 2.5 herein for schedule deviations. Such hourly imbalance charge (or credit) shall be equal to the Facility's metered incremental energy delivery minus the Facility's scheduled incremental energy delivery times the ISO imbalance price minus the PX day-ahead price. This can be expressed as:

$$IC_h = (MIE_h - SIE_h) \times (IMP_h - PXP_h)$$

Where:

IC_h = Imbalance Charge for hour (h)

MIE_h = Metered incremental energy delivery for hour (h)

SIE_h = Scheduled incremental energy delivery for hour (h)

IMP_h = ISO imbalance price for hour (h)

PXP_h = PX price for hour (h)

1.3. Incremental energy: Energy deliveries from the Facility in excess of 23,000 kw made to PG&E. Deliveries from the Facility shall not exceed 30,000 kw at any time.

1.4. Incremental energy schedule: The monthly schedule provided by Seller seven calendar days prior to 3 p.m. on the first day of the calendar month for deliveries beginning the first of the month that PG&E shall then use to schedule Seller's incremental energy into the PX's day-ahead market. These schedules may be modified by Seller by giving three calendar days advance notice to PG&E pursuant to section 3 of this Sixth Amendment.

1.5. ISO: The California Independent System Operator Corporation, a California not-for-profit public benefit corporation, established to operate the electric transmission system in the State of California, as described in sections 345-350 of the California Public Utilities Code, or its succeeding entity.

1.6. ISO imbalance price: Per megawatt-hour price or charge for uninstructed deviation within the zone in which the Facility is located for incremental (for under-delivery) and decremental (for over-delivery) generating pricing, as appropriate. The hourly ISO imbalance price shall be the average of the 10 minute ex-post prices posted on the ISO web site for each hour.

1.7. PX: The California Power Exchange Corporation, a California not-for-profit public benefit corporation, established to conduct competitive auctions for electric power in the State of California, as described in sections 355-356 of the California Public Utilities Code, or its succeeding entity.

1.8. PX price: The hourly energy market clearing price by zone published by the PX for the PX's day-ahead energy market for the zone in which the Facility is located.

2. TERMS GOVERNING DELIVERY AND PURCHASE OF INCREMENTAL ENERGY

2.1 For each hour set forth in the incremental energy schedule, Seller shall generate and deliver and PG&E will accept and pay for incremental energy deliveries from the Facility at a price equal to 90% of the PX price ($/mwh) applicable to the hour in which such incremental energy is delivered. Seller shall receive no compensation pursuant to PPA Article 4 for incremental energy deliveries.

2.2 Seller shall not be entitled to or claim compensation for any firm or as-delivered capacity payments pursuant to PPA Article 5 for incremental energy deliveries under this Sixth Amendment in any case.

2.3 If, for any reason, Seller believes the Facility will not be able to provide any incremental energy for a period of time greater than two hours, Seller shall notify PG&E's real-time trader by telephone at (415) 973-4500 within one hour of the incident contributing to lower Facility output to fully inform PG&E of the nature, extent and duration of the full or partial forced outage. Seller shall also notify, via electronic mail, Marc L. Renson

(MLR8@PGE.COM) and Soliman Elgazzar (SEE2@PGE.COM), or such other individuals designated by PG&E of the problem and revise the incremental energy schedule within three hours of the incident, or by the next business day if the problem occurs other than between the hours of 8 a.m. to 5 p.m. on weekdays (excluding holidays).

2.4 Seller shall use its best efforts to make deliveries of incremental energy to PG&E pursuant to the incremental energy schedule. Seller commits that the Facility will deliver incremental energy within a 40% bandwidth of the incremental energy scheduled in section 1.4 herein (with the Facility delivering between 60% and 140% of scheduled incremental energy).

2.5 If actual incremental energy deliveries from the Facility fall outside the bandwidth (schedule deviations) for more than 5% of the number of hours in which Seller has scheduled incremental energy during a billing month, then, at PG&E's sole discretion, Seller may be responsible for imbalance charges associated with schedule deviations in excess of the 5%. Imbalance charges shall not apply to incremental energy deliveries that are within the 40% bandwidth. If PG&E requests deviation from Seller's schedule, imbalance charges shall not apply to any imbalances resulting from such schedule deviation. All hours for which Seller has promptly notified PG&E of the full or partial forced outage of the Facility pursuant to section 2.3 herein shall be excluded from the calculation that determines if the 40% bandwidth was exceeded for more than 5% of the number of hours in which Seller has scheduled delivery of incremental energy.

2.6 PG&E's payment for incremental energy deliveries, plus or minus the sum of any imbalance charges, if applicable, will be included with payments PG&E makes in accordance with the energy payment provisions in Section A-4, Appendix A of the PPA, but shall be separately stated for accounting purposes.

2.7 Seller's decision to make deliveries of incremental energy for sale to PG&E is entirely voluntary. Seller shall be solely liable for the cost of any equipment upgrades or damage to any equipment resulting from selling incremental energy to PG&E.

2.8 Seller shall comply with all regulations, including but not limited to those imposed by the Federal Energy Regulatory Commission, e.g. 18 CFR section 292.203 and maintain compliance with all applicable environmental regulations to produce its incremental energy for sale to PG&E.

2.9 Except as provided herein, all provisions of the PPA shall remain in effect and unchanged and shall not be affected by the terms or termination hereof.

3. NOTICES

Notices pursuant to this incremental energy agreement shall conveyed via electronic mail to Marc L. Renson (MLR8@PGE.COM) and Soliman Elgazzar (SEE2@PGE.COM), or such other individuals designated by PG&E.

4. CONSTRUCTION OF AMENDMENT

4.1. Except as expressly modified by this Sixth Amendment, the provisions of the PPA as amended shall remain unchanged. This Sixth Amendment constitutes the entire agreement of the Parties with respect to the subject matter hereof and supersedes any and all prior negotiations, correspondence, understandings and agreements between the Parties respecting the sale of incremental energy contemplated hereunder.

4.2. Captions are included herein for ease of reference only. The captions are not intended to affect the meaning of the contents or scope of this Sixth Amendment.

4.3. No provision of this Sixth Amendment shall be interpreted for or against PG&E or Seller because PG&E, Seller, or their respective attorneys drafted the particular provision.

4.4. This Sixth Amendment shall be construed and interpreted in accordance with the laws of the State of California, excluding any choice of law rules that may direct the application of the laws of another jurisdiction.

4.5. No term or provision herein shall be deemed waived and no breach excused unless such waiver or excuse is in writing and signed by the Party claimed to have so waived or excused.

4.6. Each provision of this Sixth Amendment shall be interpreted so as to be valid and enforceable under applicable law. If any term or provision in this Sixth Amendment shall be held invalid or unenforceable, that provision shall be ineffective only to the extent of such invalidity or unenforceability, without thereby invalidating the remainder of the provision or any other provision in the PPA or this Sixth Amendment.

4.7. Any modification of this Sixth Amendment must be in writing and signed by authorized representatives from both Parties.

5. DISPUTE RESOLUTION

Any dispute of whatever nature that may arise out of or in relation to the interpretation, performance, or breach of this Sixth Amendment shall be resolved at the request of either Party to this Sixth Amendment through a two-step dispute resolution process.

First, the Parties shall attempt to resolve the dispute through informal negotiations. Upon written request of either Party to the other, the Parties shall, within thirty days of such request, meet and negotiate the dispute assisted by a mediator if the Parties both agree on such assistance. Seller and PG&E shall each bear its own attorney's fees and expenses incurred in any such mediation and each Party shall bear fifty percent of the fees and expenses the mediator may charge for mediation services.

Second, if the Parties cannot resolve a dispute through negotiations and/or mediation within 60 days of the initial request to negotiate, then either Party shall have 20 days to submit the matter to binding arbitration before a single arbitrator. The arbitration shall be administered according to the Commercial Dispute Resolution Procedures of the American Arbitration Association ("AAA Rules"), as they may be amended from time to time, and such arbitration shall be completed as promptly as practicable. To select an arbitrator, the Parties shall simultaneously exchange the names of three potential arbitrators. If the Parties each submit the name of the same potential arbitrator, or if the Parties can agree on one of the potential arbitrators submitted, then that person shall be selected as the arbitrator. If the Parties cannot agree on an arbitrator, then the arbitrator shall be selected according to the procedure set forth in the AAA Rules. By directing the use of the AAA Rules for arbitration, the Parties do not thereby intend to use AAA's administrative services; this reference refers only to use of the rules for the conduct of the arbitration. Seller and PG&E shall each bear fifty percent of the fees and expenses charged by the arbitrator whose services are used as prescribed in this paragraph. The site of any arbitration shall be in California. Each Party shall bear its own expenses and attorney's fees arising from resolution of any dispute under this paragraph, including expenses and fees arising from any arbitration.

6. EFFECTIVE DATE AND TERMINATION DATE

THIS SIXTH AMENDMENT shall be effective as of July 31, 2000 and shall remain in effect through the expiration date of the PPA, unless terminated earlier. Either Party may terminate this Sixth Amendment for any reason by giving written notice to the other Party at least 3 calendar days prior to the date of such termination. The termination of this Sixth Amendment shall not terminate the obligations set forth in sections 2 through 5 that, by their nature, are intended to survive such termination.

7. SIGNATURES

By signing this Sixth Amendment below, the representatives of the Parties warrant that they have the requisite authority to bind their respective Parties.

PACIFIC GAS AND ELECTRIC COMPANY	HANFORD L.P.
a California corporation	a Delaware limited partnership
	By: GWF Hanford, Inc., its Managing General Partner
By: [signature]	By: [signature]
Title: Director, USPM	Title: President & CEO
Date: 11/3/2000	Date: 10-11-2000

UNDERDELIVERY
= (Actual IE delivery minus scheduled IE delivery) X (ISO incremental energy price minus PX day-ahead price)

px day-ahead price	ISO imbalance price	sch	act	imbal	ISO minus PX	Total Payment	PX Pays PG&E on schedule	PX purchases ISO replacement energy on PG&E's behalf	Net Payment From PX
100	150	5	4	-1	-50	350	500	-150	350
100	80	5	4	-1	20	420	500	-80	420
100	0	5	4	-1	100	500	500	0	500
100	100	5	4	-1	0	400	500	-100	400
100	-25	5	4	-1	125	525	500	25	525

OVERDELIVERY
= (Actual IE delivery minus scheduled IE delivery) X (ISO decremental energy price minus PX day-ahead price)

px day-ahead price	ISO imbalance price	sch	act	imbal	ISO minus PX	Total Payment	PX Pays PG&E on schedule	Payment for energy sold in imbalance market	Net Payment From PX
100	150	4	5	1	50	550	400	150	550
100	80	4	5	1	-20	480	400	80	480
100	0	4	5	1	-100	400	400	0	400
100	100	4	5	1	0	500	400	100	500
100	-25	4	5	1	-125	375	400	-25	375

Attachment F

District Policy FYI 311

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

DATE: 1/14/13

TO: Permit Services Staff

FROM: Leonard Scandura – Permit Services Manager

SUBJECT: Quantifying Greenhouse Gas Emissions Due To Electricity Use

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Purpose:

This document is intended to provide a generally accepted greenhouse gas (GHG) emission factor (as CO2 equivalents or CO2e) for electricity utilization.

Background:

While the District does not directly regulate direct or indirect emissions of GHGs from stationary sources, there are instances when a quantification of a project's GHG emissions is required. Direct GHG emissions are those that occur on site as a result of a project. Indirect GHG emissions are those that occur off site but are due to the activity at the stationary source. Electrical consumption can result in direct GHG emissions if the electricity is generated and consumed onsite or indirect GHG emissions if the electricity is generated offsite and consumed onsite.

District Policy "Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency" provides a various methods for the District to determine significance of a project's GHG emissions. This can include quantification of a project's direct and indirect GHG emissions. Additionally, in establishing the Best Performance Standard for a given class and category of source, the direct and indirect GHG emissions from the baseline case and the similar equipment equipped with BPS must be quantified.

Additionally, Rule 2301 – Emission Reduction Credit Banking includes provisions to bank reductions in GHG emissions. GHG emission reductions are quantified as the difference between the historic actual GHG emissions and the post project potential GHG emissions from the project. Post project potential indirect GHG emissions due to an emission reduction project (due to electricity consumption) may need quantified and considered in determining the amount of GHG ERCs available.

Post project potential indirect GHG emissions due to electricity consumption are calculated using the post project potential electrical consumption (kW-hr) per year and a representative GHG emission factor (kg CO2e/kw-hr) .

Guidance:

There are a several different electricity suppliers in the District including Pacific Gas and Electric, Southern California Edison, and various municipally owned utility districts and irrigation districts. Electricity from out of state sources is consumed as well.

Further, each electricity supplier may purchase and provide electricity from a variety of power plants that can vary from day to day and year to year. Because of this variability, it would be impossible to establish a GHG emission factor for each electricity supplier in the District that would be representative of the current and future potential GHG emissions due to electricity use for a given project.

The California Energy Commission document "Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report" dated October 15, 2007 (available at http://www.climatechange.ca.gov/climate_action_team/reports/2007-10-15_MACROECONOMIC_ANALYSIS.PDF) provides an estimate of GHG emissions due to electricity consumption in California as a result of implementing various strategies to reduce GHG emissions in the State by 2020.

This document presents two different emission factors that present GHG emissions due to electricity consumption as a result of implementing these strategies. These emission factors take into account electricity produced out of state (and therefore not subject to AB32 requirements), electricity generated with renewable resources (wind, solar, hydroelectric, biomass, etc.), and transmission losses as projected in 2020.

An emission factor of 313 kg CO2e/MW-hr is identified to estimate GHG emission reductions due to improved electrical efficiency. This emission factor represents GHG emissions due to marginal decreases in electrical use due to energy efficiency projects. It can also be used to estimate GHG emissions due to marginal increases in electrical use due to new projects that consume electricity.

A separate emission factor of 390 kg CO2e/MW-hr is identified to estimate GHG emission reductions due to increased renewable electricity production. This emission factor is based on the assumption that electricity generated from renewable resources will displace electricity generated from fossil fuel combustion (which has higher GHG emissions than the total portfolio of electricity consumed in California). This emission factor is not appropriate to estimate GHG emissions due to increased electricity use.

The emission factor of 313 kg CO2e/MW-hr represents GHG emissions due to marginal electricity use. Even though this emission factor is a projection what GHG emissions from electricity consumption will be in 2020, it is accepted as a reasonable estimate to use when quantifying GHG emissions due to electricity use.

This emission factor shall be used when determining the decrease in GHG emissions due to using less electricity (as due to an energy efficiency project) or due to increased electricity use (due to installation of new equipment). In summary, when estimating GHG emissions due to electricity use for a given project, an emission factor 313 kg CO2e/Mw-hr (0.313 kg/kW-hr) shall be used.

Attachment G

Draft ERC Certificate C-1282-24

San Joaquin Valley
Air Pollution Control District

Central Regional Office • 1990 E. Gettysburg Ave. • Fresno, CA 93726

Emission Reduction Credit Certificate
C-1282-24

DRAFT

ISSUED TO: **HANFORD L P**

ISSUED DATE: **<DRAFT>**

LOCATION OF REDUCTION: **10596 IDAHO AVE**
HANFORD, CA 93230

For CO2E Reduction In The Amount Of:

175,579 metric tons / year

[ ] Conditions Attached

Method Of Reduction

[ ] Shutdown of Entire Stationary Source
[X] Shutdown of Emissions Units
[ ] Other

Shutdown of one 320 MMBtu/hr petroleum coke fired fluidized bed combustor, verified as permanent within the boundaries of the State of California

Emission Reduction Qualification Criteria

This emission reduction is surplus and additional to all applicable regulatory requirements.

Seyed Sadredin, Executive Director / APCO

DRAFT

David Warner, Director of Permit Services

Mar 31 2014 7:46AM – BROWND