GALATI | BLEK LLP

455 Capitol Mall Suite 350
Sacramento CA 95814
Tel • 916.441.6575
Fax • 916.441.6553

| DOCKET 00-AFC-1C | |
|---|---|
| DATE | 9/9/2009 |
| RECD. | 9/9/2009 |

September 9, 2009

California Energy Commission
Docket Unit
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: **REBUTTAL EXHIBITS PROPOSED BY PG&E DOCKET NO. (00-AFC-1C)**

Enclosed for filing with the California Energy Commission is the original of the **REBUTTAL EXHIBITS PROPOSED BY PG&E**, for the Gateway Generating Station Docket No.(00-AFC-1C).

Sincerely,

Marie Mills

Marie Mills

## REBUTTAL EXHIBITS PROPOSED BY PG&E

## GATEWAY GENERATING STATION (00-AFC-1C)

| | |
|---|---|
| **Exhibit No. 317** | Transmittal of PG&E/BAAQMD Compliance Agreement to CEC circa November 2008 |
| **Exhibit No. 318** | BAAQMD Documentation Confirming the Surrender of Required ERCs by Mirant in 2001 |
| **Exhibit No. 319** | December 2006 acid rain application package |
| **Exhibit No. 320** | BAAQMD Proposed Approval of Amended Authority to Construct and PSD Permit, dated 6/4/2008 |
| **Exhibit No. 321** | BAAQMD Brief on Jurisdictional Issues submitted to the US EPA Environmental Appeals Board, dated June 22, 2009, filed June 30, 2009, including Declaration of Alexander G. Crockett, Esq., dated June 22, 2009, filed June 30, 2009 |
| **Exhibit No. 322** | PG&E Brief on Jurisdictional Issues and Motion for Summary Disposition (Dismissal) submitted to US EPA Environmental Appeals Board, dated and filed July 2, 2009, including Declaration of Gary S. Rubenstein, dated July 1, 2009, filed July 2, 2009. |
| **Exhibit No. 323** | PG&E Errata to the Brief on Jurisdictional Issues and Motion for Summary Disposition (Dismissal) submitted to US EPA Environmental Appeals Board, dated and filed July 23, 2009. |
| **Exhibit No. 324** | Pacific Gas & Electric Company – BAAQMD – Second Novation to May 1, 2009 Compliance Agreement |
| **Exhibit No. 325** | EPA Finding and Notice of Violation dated August 13, 2009 |

# Exhibit No. 318

BAAQMD Documentation Confirming the Surrender of Required ERCs by Mirant in 2001

Date: 10Aug09
Application: 1000 << archived application record >>
Plant #: 18143 << POC= .0 ,NOx= .0tons/yr>>
Plant name: Gateway Generating Station
Location: 3225 Wilbur Avenue, Antioch, CA 94509
UTM coordinates: 609.01(Lon) 4207.9(Lat)
Banking #: 795
Project title: New Source/Gas Turbine
Plant Contact: Steve Royall,Plant Manager
Mailing address: 3225 Wilbur Avenue, Antioch, CA 94509
Telephone: (925) 522-7805
Engineer: Brian K Lusher [1015]
Folder : Brian K Lusher
Received: 03/06/00 . . Completeness review due by: 03/27/00
Incomplete: 03/13/00 . . . . . Cancellation due by: 07/15/00
Re-activated: 04/18/00 . . Completeness review due by: 05/10/00
Complete: 05/22/00 . . . . . Evaluation due by: 11/18/00
A/C: 07/24/01 . . . . . Expiration due by: 07/23/09

Final disposition: A/C granted 07/24/01

Emissions increase/decrease, (tons/year)

| | PM>10 | POC | NOx | SO2 | CO | PM10 |
|---|---|---|---|---|---|---|
| increase | .000 | 46.600 | 174.300 | .000 | .000 | 114.570 |
| bank no. 693 | .000 | 53.600 | 200.500 | .000 | .000 | .000 |
| offset ratio | .00 | 1.15 | 1.15 | .00 | .00 | .00 |
| bank no. 693 | .000 | .000 | .000 | .000 | .000 | 321.900 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |
| bank no. 694 | .000 | .000 | .000 | .000 | .000 | 14.251 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |
| bank no. 695 | .000 | .000 | .000 | .000 | .000 | .179 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |
| bank no. 754 | .000 | .000 | .000 | .000 | .000 | 2.370 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 1.00 |

Source: S-41; Natural Gas-fired Combustion Turbine Generator <f>
Codes: New/None
Condition #: 18138 <<f>>
Final Disposition: A/C granted, 07/24/01

Source: S-42; Heat Recovery Steam Generator (Duct Burner) <f>
Codes: New/None
Condition #: 18138 <<f>>
Final Disposition: A/C granted, 07/24/01

Source: S-43; Natural Gas-fired Combustion Turbine Generator <f>
Codes: New/None
Condition #: 18138 <<f>>
Final Disposition: A/C granted, 07/24/01

Source: S-44; Heat Recovery Steam Generator (Duct Burner) <f>
Codes: New/None
Condition #: 18138 <<f>>

Final Disposition: A/C granted, 07/24/01

Source: S-45; Natural Gas-Fired Fuel Preheater <f>
Codes: New/None
Condition #: 18138 <<f>>
Final Disposition: A/C granted, 07/24/01

Source: S-46; 10-Cell Cooling Tower <f>
Codes: New/None
Condition #: 18138 <<f>>
Final Disposition: A/C granted, 07/24/01

Abatement Device: A-14; CO Oxidizing Catalyst <f>
Codes: New/None
Final Disposition: A/C granted, 07/24/01

Abatement Device: A-13; Selective Catalytic Reduction with Ammonia Injectio
Codes: New/None
Condition #: 18138 <<f>>
Final Disposition: A/C granted, 07/24/01

Abatement Device: A-12; CO oxidizing catalyst <f>
Codes: New/None
Final Disposition: A/C granted, 07/24/01

Abatement Device: A-11; Selective Catalytic Reduction with ammonia injectio
Codes: New/None
Condition #: 18138 <<f>>
Final Disposition: A/C granted, 07/24/01

Banking Certificate: 693

Application no: 1708
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Crown Zellerbach Corp [Antioch]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 285
Original cert.#: 35

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | 321.900 | .000 | .000 | 209.900 |
| Approved | .000 | 125.880 | 437.560 | .000 | 450.600 | .000 | 531.800 |
| Applic: 1000 Withdrawal | .000 | 53.600 | 200.500 | .000 | .000 | .000 | .000 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | 321.900 |
| Applic: 1000 To B#: 754 | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

Banking Certificate: 694

Application no: 1710
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Pacific Gas & Electric Co, Martinez Plant [Martinez]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 73
Original cert.#: 73

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | 158.200 | .000 | .000 | 25.000 |
| Approved | .000 | 5.300 | 299.000 | 143.679 | 114.000 | .000 | 39.521 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | 14.251 |
| Applic: 1000 To B#: 755 | .000 | 5.300 | 299.000 | 143.679 | 114.000 | .000 | 25.270 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

Banking Certificate: 695

Application no: 1711
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Hudson ICS [San Leandro]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 616
Original cert.#: 394

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .179 | .000 | .000 | 6.443 |
| Approved | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.622 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | .179 |
| Applic: 1000 To B#: 756 | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.443 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

Banking Certificate: 754

Application no: 1000
Final Disposition: Certificate Issued 07/19/01
Reduction Location: Crown Zellerbach Corp [Antioch]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 693
Original cert.#: 35

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .000 | .000 | .000 | .000 |
| Approved | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | 2.370 |
| Applic: 1000 To B#: 795 | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 207.530 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
(Vice Chairperson)
Nate Miley
Shelia Young

CONTRA COSTA COUNTY
Mark DeSaulnier
Mark Ross
Gayle Uilkema

MARIN COUNTY
Harold C. Brown, Jr.

NAPA COUNTY
Brad Wagenknecht

SAN FRANCISCO COUNTY
Chris Daly
Tony Hall
Leland Yee

SAN MATEO COUNTY
Jerry Hill
Marland Townsend
(Secretary)

SANTA CLARA COUNTY
Randy Attaway
(Chairperson)
Liz Kniss
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**December 18, 2001**

**Mirant California**
**1350 Treat Blvd, Suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1000 BANKING CERTIFICATE 795

In accordance with Section 2-4-412.2 of the District's Regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (<10 microns) | 207.530 | tons/year |
| Precursor Organic Compounds | 72.280 | tons/year |
| Nitrogen Oxides | 237.060 | tons/year |
| Carbon Monoxide | 450.600 | tons/year |

are the remaining credits from banking certificate 754. These emission reduction credits represent the unused portion of the certificate that was surrendered to offset the additional increase of 2.37 tons/year $PM_{10}$ of application 1000.

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **Dick Wocasek, Air Quality Engineer II at (415) 749-4984.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By _____
Permit Services Division

FRW/db
Enclosure: Certificate 795

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

**Certificate of Deposit 795**

**Mirant California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1000:

| | | |
|---|---|---|
| **Particulate Matter (<10 microns)** | **207.530** | **tons/year** |
| **Precursor Organic Compounds** | **72.280** | **tons/year** |
| **Nitrogen Oxides** | **237.060** | **tons/year** |
| **Carbon Monoxide** | **450.600** | **tons/year** |

Emission Reduction Location: Crown Zellerbach Corp.
Antioch, CA

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 12/26/01

**By** _____
**Permit Services Division**

list banking NUMBER, (or enter ? for other options) >> 693

Banking Certificate: 693

Application no: 1708
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Crown Zellerbach Corp [Antioch]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 285
Original cert.#: 35

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | 321.900 | .000 | .000 | 209.900 |
| Approved | .000 | 125.880 | 437.560 | .000 | 450.600 | .000 | 531.800 |
| Applic: 1000 Withdrawal | .000 | 53.600 | 200.500 | .000 | .000 | .000 | .000 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | 321.900 |
| Applic: 1000 To B#: 754 | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

list banking NUMBER, (or enter ? for other options) >> 754

Banking Certificate: 754

Application no: 1000
Final Disposition: Certificate Issued 07/19/01
Reduction Location: Crown Zellerbach Corp [Antioch]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 693
Original cert.#: 35

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .000 | .000 | .000 | .000 |
| Approved | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |
| Balance | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |

list banking NUMBER, (or enter ? for other options) >> 694

Banking Certificate: 694

Application no: 1710
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Pacific Gas & Electric Co, Martinez Plant [Martinez]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 73
Original cert.#: 73

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | 158.200 | .000 | .000 | 25.000 |
| Approved | .000 | 5.300 | 299.000 | 143.679 | 114.000 | .000 | 39.521 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | 14.251 |
| Applic: 1000 To B#: 755 | .000 | 5.300 | 299.000 | 143.679 | 114.000 | .000 | 25.270 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

list banking NUMBER, (or enter ? for other options) >> 755

Banking Certificate: 755

Application no: 1000
Final Disposition: Certificate Issued 07/19/01
Reduction Location: Pacific Gas & Electric Co, Martinez Plant [Martinez]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 694
Original cert.#: 73

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .000 | .000 | .000 | .000 |
| Approved | .000 | 5.300 | 299.000 | 143.679 | 114.000 | .000 | 25.270 |
| Balance | .000 | 5.300 | 299.000 | 143.679 | 114.000 | .000 | 25.270 |

list banking NUMBER, (or enter ? for other options) >> 695

Banking Certificate: 695

Application no: 1711
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Hudson ICS [San Leandro]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 616
Original cert.#: 394

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .179 | .000 | .000 | 6.443 |
| Approved | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.622 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | .179 |
| Applic: 1000 To B#: 756 | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.443 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

list banking NUMBER, (or enter ? for other options) >> 756

Banking Certificate: 756

Application no: 1000
Final Disposition: Certificate Issued 07/19/01
Reduction Location: Hudson ICS [San Leandro]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 695
Original cert.#: 394

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .000 | .000 | .000 | .000 |
| Approved | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.443 |
| Balance | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.443 |

type '?' for SHOWPERM commands >> 1000

```
             Date: 19Jul01
      Application: 1000
            Plant #: 18                    << POC=  21.8  ,NOx=1660.7tons/yr>>
        Plant name: Mirant Delta, LLC
          Location: 1456 Wilbur Avenue, Antioch, CA  94509
   UTM coordinates: 606.51(Lon)   4207.7(Lat)
     Project title: New Source/Gas Turbine
     Plant Contact: Joseph Bittner,Plant Manager
   Mailing address: P O Box 1687, Antioch, CA  94509
         Telephone: (925) 427-3597
          Engineer: F Richard Wocasek   [653]
           Folder : F Richard Wocasek
          Received: 03/06/00 . . Completeness review due by: 03/27/00
        Incomplete: 03/13/00 . . . . .  Cancellation due by: 07/15/00
      Re-activated: 04/18/00 . . Completeness review due by: 05/10/00
          Complete: 05/22/00 . . . . . .  Evaluation due by: 11/18/00

       Last Billed:  255230.00  03/13/00
      Total Billed:  255230.00
           Payment:  255230.00  Log#21886
                     --------
        Total Paid:  255230.00
```

Emissions increase/decrease, (tons/year)

| | PM>10 | POC | NOx | SO2 | CO | PM10 |
|---|---|---|---|---|---|---|
| increase | .000 | 46.600 | 174.300 | .000 | .000 | 112.200 |
| bank no. 693 | .000 | 53.600 | 200.500 | .000 | .000 | .000 |
| offset ratio | .00 | 1.15 | 1.15 | .00 | .00 | .00 |
| bank no. 693 | .000 | .000 | .000 | .000 | .000 | 321.900 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |
| bank no. 695 | .000 | .000 | .000 | .000 | .000 | .179 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |
| bank no. 694 | .000 | .000 | .000 | .000 | .000 | 14.251 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |

list banking NUMBER, (or enter ? for other options) >> 695

Banking Certificate: 695

Application no: 1711
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Hudson ICS [San Leandro]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 616
Original cert.#: 394

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .179 | .000 | .000 | 6.443 |
| Approved | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.622 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | .179 |
| Applic: 1000 To B#: 756 | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.443 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

list banking NUMBER, (or enter ? for other options) >> 756

Banking Certificate: 756

Application no: 1000
Final Disposition: Certificate Issued 07/19/01
Reduction Location: Hudson ICS [San Leandro]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 695
Original cert.#: 394

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .000 | .000 | .000 | .000 |
| Approved | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.443 |
| Balance | 4.200 | .390 | 1.173 | .000 | 14.602 | .000 | 6.443 |

type '?' for SHOWPERM commands >> 1000

```
             Date: 19Jul01
      Application: 1000
            Plant #: 18                    << POC=  21.8  ,NOx=1660.7tons/yr>>
       Plant name: Mirant Delta, LLC
         Location: 1456 Wilbur Avenue, Antioch, CA  94509
  UTM coordinates: 606.51(Lon)   4207.7(Lat)
    Project title: New Source/Gas Turbine
    Plant Contact: Joseph Bittner,Plant Manager
  Mailing address: P O Box 1687, Antioch, CA  94509
        Telephone: (925) 427-3597
         Engineer: F Richard Wocasek   [653]
          Folder : F Richard Wocasek
         Received: 03/06/00 . . Completeness review due by: 03/27/00
       Incomplete: 03/13/00 . . . . .  Cancellation due by: 07/15/00
     Re-activated: 04/18/00 . . Completeness review due by: 05/10/00
         Complete: 05/22/00 . . . . . .  Evaluation due by: 11/18/00

      Last Billed:  255230.00  03/13/00
     Total Billed:  255230.00
          Payment:  255230.00  Log#21886
                    --------
       Total Paid:  255230.00
```

Emissions increase/decrease, (tons/year)

| | PM>10 | POC | NOx | SO2 | CO | PM10 |
|---|---|---|---|---|---|---|
| increase | .000 | 46.600 | 174.300 | .000 | .000 | 112.200 |
| bank no. 693 | .000 | 53.600 | 200.500 | .000 | .000 | .000 |
| offset ratio | .00 | 1.15 | 1.15 | .00 | .00 | .00 |
| bank no. 693 | .000 | .000 | .000 | .000 | .000 | 321.900 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |
| bank no. 695 | .000 | .000 | .000 | .000 | .000 | .179 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |
| bank no. 694 | .000 | .000 | .000 | .000 | .000 | 14.251 |
| offset ratio | .00 | .00 | .00 | .00 | .00 | 3.00 |

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
(Vice Chairperson)
Nate Miley
Shelia Young

CONTRA COSTA COUNTY
Mark DeSaulnier
Mark Ross
Gayle Uilkema

MARIN COUNTY
Harold C. Brown, Jr.

NAPA COUNTY
Brad Wagenknecht

SAN FRANCISCO COUNTY
Chris Daly
Tony Hall
Leland Yee

SAN MATEO COUNTY
Jerry Hill
Marland Townsend
(Secretary)

SANTA CLARA COUNTY
Randy Attaway
(Chairperson)
Liz Kniss
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**July 24, 2001**

**Mirant California**
**1350 Treat Blvd, Suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1000 BANKING CERTIFICATE 756

In accordance with Section 2-4-412.2 of the District's Regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (>10 microns) | 4.200 | tons/year |
| Particulate Matter (<10 microns) | 6.443 | tons/year |
| Precursor Organic Compounds | 0.390 | tons/year |
| Nitrogen Oxides | 1.173 | tons/year |
| Carbon Monoxide | 14.602 | tons/year |

are the remaining credits from banking certificate 695. These emission reduction credits represent the unused portion of the certificate that was surrendered to offset the emission increase of application 1000.

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **Dick Wocasek, Air Quality Engineer II at (415) 749-4984.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By Wade Boisblanc
Permit Services Division

FRW/db
Enclosure: Certificate 756

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

**Certificate of Deposit 756**

**Mirant California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1000:

| | | |
|---|---|---|
| **Particulate Matter (>10 microns)** | **4.200** | **tons/year** |
| **Particulate Matter (<10 microns)** | **6.443** | **tons/year** |
| **Precursor Organic Compounds** | **0.390** | **tons/year** |
| **Nitrogen Oxides** | **1.173** | **tons/year** |
| **Carbon Monoxide** | **14.602** | **tons/year** |

Emission Reduction Location: Hudson ICS
San Leandro, CA

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 7/24/01

**By** Wade Bristlane
**Permit Services Division**

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
(Vice Chairperson)
Nate Miley
Shelia Young

CONTRA COSTA COUNTY
Mark DeSaulnier
Mark Ross
Gayle Uilkema

MARIN COUNTY
Harold C. Brown, Jr.

NAPA COUNTY
Brad Wagenknecht

SAN FRANCISCO COUNTY
Chris Daly
Tony Hall
Leland Yee

SAN MATEO COUNTY
Jerry Hill
Marland Townsend
(Secretary)

SANTA CLARA COUNTY
Randy Attaway
(Chairperson)
Liz Kniss
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**July 24, 2001**

**Mirant California**
**1350 Treat Blvd, Suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1000 BANKING CERTIFICATE 754

In accordance with Section 2-4-412.2 of the District's Regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (<10 microns) | 209.900 | tons/year |
| Precursor Organic Compounds | 72.280 | tons/year |
| Nitrogen Oxides | 237.060 | tons/year |
| Carbon Monoxide | 450.600 | tons/year |

are the remaining credits from banking certificate 693. These emission reduction credits represent the unused portion of the certificate that was surrendered to offset the emission increase of application 1000.

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **Dick Wocasek, Air Quality Engineer II at (415) 749-4984.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By
Permit Services Division

FRW/db
Enclosure: Certificate 754

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

Certificate of Deposit 754

**Mirant California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1000:

| | | |
|---|---|---|
| **Particulate Matter (<10 microns)** | **209.900** | **tons/year** |
| **Precursor Organic Compounds** | **72.280** | **tons/year** |
| **Nitrogen Oxides** | **237.060** | **tons/year** |
| **Carbon Monoxide** | **450.600** | **tons/year** |

Emission Reduction Location: Crown Zellerbach Corp.
Antioch, CA

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 7/24/01

**By** W. de Boisblanc
**Permit Services Division**

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
(Vice Chairperson)
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SOLANO COUNTY
William Carroll

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**July 24, 2001**

**Mirant California**
**1350 Treat Blvd, Suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1000 BANKING CERTIFICATE 755

In accordance with Section 2-4-412.2 of the District's Regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (<10 microns) | 25.270 | tons/year |
| Precursor Organic Compounds | 5.300 | tons/year |
| Nitrogen Oxides | 299.000 | tons/year |
| Sulfur Dioxide | 143.679 | tons/year |
| Carbon Monoxide | 114.000 | tons/year |

are the remaining credits from banking certificate 694. These emission reduction credits represent the unused portion of the certificate that was surrendered to offset the emission increase of application 1000.

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **Dick Wocasek, Air Quality Engineer II at (415) 749-4984.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By Wade Boisblanc
Permit Services Division

FRW/db
Enclosure: Certificate 755

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

Certificate of Deposit 755

**Mirant California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1000:

| | | |
|---|---|---|
| **Particulate Matter (<10 microns)** | **25.270** | **tons/year** |
| **Precursor Organic Compounds** | **5.300** | **tons/year** |
| **Nitrogen Oxides** | **299.000** | **tons/year** |
| **Sulfur Dioxide** | **143.679** | **tons/year** |
| **Carbon Monoxide** | **114.000** | **tons/year** |

Emission Reduction Location: Pacific Gas & Electric Co.
Martinez, CA

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 7/24/01

**By** Wade Boisclair
**Permit Services Division**

list banking NUMBER, (or enter ? for other options) >> 693

Banking Certificate: 693

Application no: 1708
Final Disposition: Certificate Issued 09/06/00
Reduction Location: Crown Zellerbach Corp [Antioch]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 285
Original cert.#: 35

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | 321.900 | .000 | .000 | 209.900 |
| Approved | .000 | 125.880 | 437.560 | .000 | 450.600 | .000 | 531.800 |
| Applic: 1000 Withdrawal | .000 | 53.600 | 200.500 | .000 | .000 | .000 | .000 |
| Applic: 1000 Withdrawal | .000 | .000 | .000 | .000 | .000 | .000 | 321.900 |
| Applic: 1000 To B#: 754 | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |
| Balance | .000 | .000 | .000 | .000 | .000 | .000 | .000 |

list banking NUMBER, (or enter ? for other options) >> 754

Banking Certificate: 754

Application no: 1000
Final Disposition: Certificate Issued 07/19/01
Reduction Location: Crown Zellerbach Corp [Antioch]
Certificate owner: Mirant
Contact: Ron Kino, tel: (925) 287-3118
Mailing address: 1350 Treat Blvd, suite 500, Walnut Creek, CA 9459

Transfer from #: 693
Original cert.#: 35

| tons per year | PM | POC | NOX | SO2 | CO | NPOC | PM10 |
|---|---|---|---|---|---|---|---|
| Requested | .000 | .000 | .000 | .000 | .000 | .000 | .000 |
| Approved | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |
| Balance | .000 | 72.280 | 237.060 | .000 | 450.600 | .000 | 209.900 |

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

Certificate of Deposit **693**

**Southern Energy California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1708:

| | | |
|---|---|---|
| **Particulate Matter (<10 microns)** | **209.900** | **tons/year** |
| **Precursor Organic Compounds** | **125.880** | **tons/year** |
| **Nitrogen Oxides** | **437.560** | **tons/year** |
| **Sulfur Dioxide** | **321.900** | **tons/year** |
| **Carbon Monoxide** | **450.600** | **tons/year** |

Surrendered

Appr. 1000 deductions

POC - 53.6 tpy

NOx - 200.5 tpy

SOx - 321.9 tpy (for $PM_{10}$)

Balance reissued as cert. no 754

DMB 7/23/01

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 9/12/2000

**By** W de Boisblanc
**Permit Services Division**

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
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Shelia Young

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Mark DeSaulnier
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(Vice Chairperson)
Don Gage
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll
(Secretary)

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**September 11, 2000**

**Southern Energy California**
**1350 Treat Blvd, suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1708 BANKING CERTIFICATE 693

In accordance with Section 2-4-412.3 of the District's regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (<10 microns) | 209.900 | tons/year |
| Precursor Organic Compounds | 125.880 | tons/year |
| Nitrogen Oxides | 437.560 | tons/year |
| Sulfur Dioxide | 321.900 | tons/year |
| Carbon Monoxide | 450.600 | tons/year |

have been transferred to you from:

**Gaylord Container Corporation**

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **David M Brunelle, at (415) 749-4684.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By W de Boisblanc
Permit Services Division

/db
Enclosure: Banking Certificate 693

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

Certificate of Deposit 694

**Southern Energy California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1710:

| | | |
|---|---|---|
| **Particulate Matter (<10 microns)** | **25.000** | **tons/year** |
| **Precursor Organic Compounds** | **5.300** | **tons/year** |
| **Nitrogen Oxides** | **299.000** | **tons/year** |
| **Sulfur Dioxide** | **158.200** | **tons/year** |
| **Carbon Monoxide** | **114.000** | **tons/year** |

Surrendered

14,251 tons of SOx used to offset PM10 in application no. 1000.
Balance reissued as cert. no. 755
DMB 7/23/01

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 9/12/2000

**By** Wade Boisblanc
**Permit Services Division**

BAY AREA
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DISTRICT

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NAPA COUNTY
Brad Wagenknecht

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Amos Brown
Michael Yaki

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Marland Townsend

SANTA CLARA COUNTY
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(Vice Chairperson)
Don Gage
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll
(Secretary)

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**September 12, 2000**

**Southern Energy California**
**1350 Treat Blvd, suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1710 BANKING CERTIFICATE 694

In accordance with Section 2-4-412.3 of the District's regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (<10 microns) | 25.000 | tons/year |
| Precursor Organic Compounds | 5.300 | tons/year |
| Nitrogen Oxides | 299.000 | tons/year |
| Sulfur Dioxide | 158.200 | tons/year |
| Carbon Monoxide | 114.000 | tons/year |

have been transferred to you from:

**Pacific Gas and Electric Company**

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **David M Brunelle, at (415) 749-4684.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By W deBoisblanc
Permit Services Division

/db
Enclosure: Banking Certificate 694

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

Certificate of Deposit 695

**Southern Energy California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1711:

| | | |
|---|---|---|
| **Particulate Matter (>10 microns)** | **4.200** | **tons/year** |
| **Particulate Matter (<10 microns)** | **6.443** | **tons/year** |
| **Precursor Organic Compounds** | **0.390** | **tons/year** |
| **Nitrogen Oxides** | **1.173** | **tons/year** |
| **Sulfur Dioxide** | **0.179** | **tons/year** |
| **Carbon Monoxide** | **14.602** | **tons/year** |

Suspended.

0.179 tons/yr $SO_2$ used to offset $PM_{10}$ in application no. 1000.
Balance reissued as cert. no. 756.

DMB 7/23/01

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 9/12/2000

**By** W. DeBoris Blanc
**Permit Services Division**

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
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NAPA COUNTY
Brad Wagenknecht

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Michael Yaki

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(Vice Chairperson)
Don Gage
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll
(Secretary)

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**September 11, 2000**

**Southern Energy California**
**1350 Treat Blvd, suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1711 BANKING CERTIFICATE 695

In accordance with Section 2-4-412.3 of the District's regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (>10 microns) | 4.200 | tons/year |
| Particulate Matter (<10 microns) | 6.443 | tons/year |
| Precursor Organic Compounds | 0.390 | tons/year |
| Nitrogen Oxides | 1.173 | tons/year |
| Sulfur Dioxide | 0.179 | tons/year |
| Carbon Monoxide | 14.602 | tons/year |

have been transferred to you from:

**Hudson ICS**

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **David M Brunelle, at (415) 749-4684.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By W. de Boo Blanc
Permit Services Division

/db
Enclosure: Banking Certificate 695

Mirant Corporation
1350 Treat Boulevard, Suite 500, Walnut Creek, CA 94596
T 925 287 3100 F 925 947 3001 U www.mirant.com

MIRANT™

# Facsimile Sheet

| | | | |
|---|---|---|---|
| To | Dick Wocasek | Date | 7/18/01 |
| Company | BAAQMD | Facsimile | 415-749-5030 |
| From | RON KINO - MIRANT | Telephone | 925-287-3118 |
| Subject | | # of pages including cover sheet | -7- |

Remarks ○ Urgent ○ Reply ASAP ○ Review ○ Comment

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
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Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**September 11, 2000**

**Southern Energy California**
**1350 Treat Blvd, suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1708 BANKING CERTIFICATE 693

In accordance with Section 2-4-412.3 of the District's regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (<10 microns) | 209.900 | tons/year |
| Precursor Organic Compounds | 125.880 | tons/year |
| Nitrogen Oxides | 437.560 | tons/year |
| Sulfur Dioxide | 321.900 | tons/year |
| Carbon Monoxide | 450.600 | tons/year |

have been transferred to you from:

**Gaylord Container Corporation**

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **David M Brunelle, at (415) 749-4684.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By W de Boisblanc
Permit Services Division

/db
Enclosure: Banking Certificate 693

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

Certificate of Deposit 693

**Southern Energy California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1708:

| | | |
|---|---|---|
| **Particulate Matter (<10 microns)** | **209.900** | **tons/year** |
| **Precursor Organic Compounds** | **125.880** | **tons/year** |
| **Nitrogen Oxides** | **437.560** | **tons/year** |
| **Sulfur Dioxide** | **321.900** | **tons/year** |
| **Carbon Monoxide** | **450.600** | **tons/year** |

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 9/12/2000

**By** W de Bourbelanc
**Permit Services Division**

BAY AREA
AIR QUALITY
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DISTRICT

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William Carroll
(Secretary)

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Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

**September 12, 2000**

**Southern Energy California**
**1350 Treat Blvd, suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1710 BANKING CERTIFICATE 694

In accordance with Section 2-4-412.3 of the District's regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (<10 microns) | 25.000 | tons/year |
| Precursor Organic Compounds | 5.300 | tons/year |
| Nitrogen Oxides | 299.000 | tons/year |
| Sulfur Dioxide | 158.200 | tons/year |
| Carbon Monoxide | 114.000 | tons/year |

have been transferred to you from:

**Pacific Gas and Electric Company**

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **David M Brunelle, at (415) 749-4684.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By W deBoisblanc
Permit Services Division

/db
Enclosure: Banking Certificate 694

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

Certificate of Deposit 694

**Southern Energy California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1710:

| | | |
|---|---|---|
| **Particulate Matter (<10 microns)** | **25.000** | **tons/year** |
| **Precursor Organic Compounds** | **5.300** | **tons/year** |
| **Nitrogen Oxides** | **299.000** | **tons/year** |
| **Sulfur Dioxide** | **158.200** | **tons/year** |
| **Carbon Monoxide** | **114.000** | **tons/year** |

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 9/12/2000

**By** Wade Boisblanc
**Permit Services Division**

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Ellen Garvey
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AIR POLLUTION
CONTROL OFFICER

**September 11, 2000**

**Southern Energy California**
**1350 Treat Blvd, suite 500**
**Walnut Creek, CA 94596**

Attention: **Ron Kino**

Dear Applicant:

SUBJECT: APPLICATION 1711 BANKING CERTIFICATE 695

In accordance with Section 2-4-412.3 of the District's regulations, the following emission reduction credits:

| | | |
|---|---|---|
| Particulate Matter (>10 microns) | 4.200 | tons/year |
| Particulate Matter (<10 microns) | 6.443 | tons/year |
| Precursor Organic Compounds | 0.390 | tons/year |
| Nitrogen Oxides | 1.173 | tons/year |
| Sulfur Dioxide | 0.179 | tons/year |
| Carbon Monoxide | 14.602 | tons/year |

have been transferred to you from:

**Hudson ICS**

Please include your application number with any correspondence with the District. If you have any questions on this matter, please call **David M Brunelle, at (415) 749-4684.**

Very truly yours,

Ellen Garvey
Executive Officer / Air Pollution Control Officer

By W. de Boro Blanc
Permit Services Division

/db
Enclosure: Banking Certificate 695

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

## EMISSION REDUCTION BANK

**Certificate of Deposit 695**

**Southern Energy California**

is hereby certified as the holder of the following emission reduction credits, approved pursuant to application number 1711:

| | | |
|---|---|---|
| **Particulate Matter (>10 microns)** | **4.200** | **tons/year** |
| **Particulate Matter (<10 microns)** | **6.443** | **tons/year** |
| **Precursor Organic Compounds** | **0.390** | **tons/year** |
| **Nitrogen Oxides** | **1.173** | **tons/year** |
| **Sulfur Dioxide** | **0.179** | **tons/year** |
| **Carbon Monoxide** | **14.602** | **tons/year** |

**Ellen Garvey**
**Executive Officer/**
**Air Pollution Control Officer**

**Date** 9/12/2000

**By** W. de Boisblanc
**Permit Services Division**

# Exhibit No. 317

Transmittal of PG&E/BAAQMD Compliance Agreement to CEC circa November 2008

## Scott Galati

**From:** Espiritu, Angel B [ABE4@PGE.COM]
**Sent:** Friday, December 05, 2008 9:26 AM
**To:** Ryasny@energy.state.ca.us
**Cc:** Maring, Jon; Allen, Thomas; Royall, Steve; Kraska, David (Law); DeBono, Teresa; Andrea@agrenier.com; Nancy L. Matthews; Gary Rubenstein; Villanueva, Rodrigo; Flander, Richard; Mosley, Judi (Law); Utic, William; Leung, Alan
**Subject:** CEC Condition AQ-29,30, and 32
**Attachments:** CEC Cond 29 30 32 BAAQMD-GGS Compliance Agreement.pdf

Ron,

Attached is an advance electronic copy of fully executed Compliance Agreement between the Bay Area Air Quality Management District (BAAQMD) and the Pacific Gas and Electric Company Gateway Generating Station (GGS) to allow GGS to complete the source testing required by BAAQMD Authority to Construct Condition Numbers 29, 30, and 32, and the California Energy Commission (CEC) Conditions of Certification AQ-29, AQ-30, and AQ-32 within 90 days of startup date. A hard copy of same will follow by mail.

Please let me know if you have questions. Thank you.

Angel Espiritu
PG&E Gateway Generating Station
Environmental Compliance
925-459-7212

# Pacific Gas & Electric Co.-BAAQMD
# Compliance Agreement

This Compliance Agreement ("Agreement") is entered into this 25 day of November, 2008, between Pacific Gas & Electric Co. ("PG&E") and the Bay Area Air Quality Management District ("BAAQMD" or "District"), hereinafter collectively referred to as the "Parties."

## RECITALS

WHEREAS, the District is the regional agency with primary responsibility for the control of air pollution from stationary sources in the San Francisco Bay Area Air Basin;

WHEREAS, PG&E owns and operates an electric power generating facility known as the Gateway Generating Station within the San Francisco Bay Area Air Basin, located at 3225 Wilbur Avenue in Antioch, CA, which is subject to District permitting jurisdiction;

WHEREAS, PG&E has been issued an Authority to Construct by the District authorizing the construction and initial operation of two combustion gas turbines at the facility (along with heat recovery steam generators and other related equipment), subject to various conditions designed to ensure compliance with applicable air pollution control regulations;

WHEREAS, conditions Nos. 29, 30 and 32 of the Authority to Construct require PG&E to conduct a source test of its equipment within 60 days of initial startup of the facility;

WHEREAS, PG&E has altered its original commissioning plan for the facility so that it can install pollution control equipment known as an oxidation catalyst at an earlier stage of commissioning than was originally anticipated;

WHEREAS, the early installation of the oxidation catalyst will result in additional emissions reductions above what was contemplated in the original commissioning plan;

WHEREAS, the additional time needed for the early installation of the oxidation catalyst under the revised commissioning plan means that it will not be possible for PG&E to complete the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct within 60 days as required by those Conditions;

WHEREAS, under the revised commissioning plan PG&E will require up to 90 days from startup to complete the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct;

WHEREAS, PG&E's revised commissioning plan does not call for actual turbine operation on more than 60 individual days before the anticipated completion of the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct;

WHEREAS, it appears to the District (i) that PG&E has acted reasonably in adjusting its commissioning plan and reasonably needs extra time to complete the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct in order to install the oxidation catalyst; (ii) that there will be no potential for environmental harm from taking extra time to

complete the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct because the maximum of number of days of actual turbine operation prior to completion of the testing will not increase; and (iii) that under the circumstances any drawbacks of extending the deadline for completing the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct will be outweighed by the benefits of PG&E's early installation of the oxidation catalyst under the revised commissioning plan;

WHEREAS, it appears to the District that under the circumstances PG&E may be eligible for immunity from enforcement action pursuant to the variance provisions of the Health & Safety Code, if PG&E were to avail itself of them; and

WHEREAS, the District is vested with:

(i) enforcement authority for the air pollution control program in accordance with California Health & Safety Code Sections 40001, 40701, 40752, 42400-42421, and 42451-42454; and

(ii) discretion over the application of this enforcement authority given the facts and circumstances of each enforcement matter,

and has determined that, in view of the circumstances recited above, it will not take civil or criminal penalty action against PG&E for failing to complete its initial source test within 60 days as required by Conditions Nos. 29, 30 and 32 of the Authority to Construct, as long as PG&E strictly adheres to the conditions set forth in this Agreement.

## AGREEMENT

NOW, THEREFORE, based on the foregoing recitals, and in consideration of the mutual promises and covenants contained in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. PG&E shall complete the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct within 90 days of startup.

2. PG&E shall not operate either combustion turbine on more than 60 individual calendar days before completion of the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct. For purposes of this Agreement, operation of a turbine during any part of a calendar day shall constitute operation on that day.

3. PG&E shall maintain written records of all times of turbine operation until completion of the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct. PG&E shall make such records available to the District for inspection upon request at any time, and shall submit copies of the final records to the District upon completion of the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct.

4. The District agrees that it shall not issue a Notice of Violation, seek civil or criminal penalties, or otherwise take enforcement action against PG&E for failure to complete the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct within 60 days of startup, as long as PG&E complies with all provisions of this Agreement. The

District reserves the right, in its discretion, to take any and all enforcement action against PG&E should PG&E fail to complete the source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct within 90 days of startup as required by this Agreement, or if PG&E operates the turbines on more than 60 separate calendar days prior to completion of source testing required by Conditions Nos. 29, 30 and 32 of the Authority to Construct. The District also reserves the right, in its discretion, to take any and all enforcement action for violation of any other permit or regulatory requirement not addressed by this Agreement.

5. Nothing in this Agreement excuses PG&E from compliance with any requirements under its Authority to Construct or District regulations except as expressly provided in this Agreement.

6. This Agreement is binding upon PG&E and the District only with respect to the matters specifically addressed and does not otherwise bind PG&E and/or the District.

7. The terms of this Agreement shall inure to the benefit of and be binding upon the Parties and their respective predecessors, successors, subsidiaries, partners, limited partners, agents, principals, and assigns.

8. If any provision of this Agreement or the application of this Agreement to either PG&E or the District is held by any judicial authority to be invalid, the application of such provision to the other Party and the remainder of this Agreement shall remain in force and shall not be affected thereby, unless such holding materially changes the terms of this Agreement.

9. Each of the undersigned represents and warrants that he or she has read and understands and has full and complete lawful authority to grant, bargain, convey, and undertake the rights and duties contained in this Agreement, and that he or she has full and complete lawful authority to bind any respective principals, successors, subsidiaries, partners, limited partners, agents and assigns to this Agreement. Each of the undersigned understands and agrees that this representation and warranty is a material term of this Agreement, without which it would not have been executed.

10. PG&E and the District each hereby affirms and acknowledges that it has read this Agreement, that it knows and understands the terms of this Agreement, and that it has signed this Agreement voluntarily. The Parties have had the opportunity to consult with their respective attorneys and any other consultant each deemed appropriate prior to executing this Agreement.

11. This Agreement shall be governed by and construed in accordance with the laws of the State of California.

12. The mutual obligations and undertakings of PG&E on the one hand, and the District on the other hand, expressly set forth in this Agreement are the sole and only consideration of this Agreement and supersede and replace all prior negotiations and proposed agreements between PG&E and the District, written or oral, on the specific matters addressed in this Agreement. PG&E and the District each acknowledges that no other party, nor the agents nor attorneys of any other party, has made any promise, representation or warranty whatsoever (express or implied), not contained herein, to induce the execution of this Agreement. This Agreement constitutes the full, complete and final statement of PG&E and the District on the matters addressed by this Agreement.

13. This Agreement may be executed in one or more counterparts, each of which shall have the same force and effect as an original, but all of which together shall constitute one and the same instrument.

14. PG&E and the District have jointly prepared this Agreement. This Agreement shall be deemed to have been jointly drafted by the Parties for the purpose of applying any rule of construction to the effect that ambiguities are to be construed against the party drafting the agreement.

15. This Agreement may be amended and supplemented only by a written instrument signed by both PG&E and the District or their successors-in-interest. However, such execution may be in counterparts and, when so executed, shall be deemed to constitute one and the same document.

16. Any material breach of this Agreement by either Party shall make the Agreement subject to termination upon notice by the non-breaching Party.

17. The waiver of any provision or term of this Agreement shall not be deemed as a waiver of any other provision or term of this Agreement. The mere passage of time, or failure to act upon a breach, shall not be deemed as a waiver of any provision or term of this Agreement.

IN WITNESS WHEREOF, the Parties acknowledge, agree to and accept this Agreement.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

By: _____
Jack P. Broadbent
Air Pollution Control Officer/
Chief Executive Officer

Date: 12/4/08

Approved as to form:

_____
Brian C. Bunger, Esq.
District Counsel

Date: _____

PACIFIC GAS & ELECTRIC CO.

By: _____
Jon Maring
Sr. Director, Fossil Plant Construction

Date: 11/25/08

Approved as to form:

_____
David Kraska
Director and Counsel

Date: 11/25/08

# Exhibit No. 319

December 2006 acid rain application package

sierra research

1801 J Street
Sacramento, CA 95814
Tel: (916) 444-6666
Fax: (916) 444-8373

Ann Arbor, MI
Tel: (734) 761-6666
Fax: (734) 761-6755

January 2, 2007

Jack Broadbent
Executive Officer and APCO
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Acid Rain Permit Application for the Gateway Generating Station (ORIS Code 56476)

Dear Mr. Broadbent:

On behalf of Pacific Gas & Electric Company, we are pleased to submit this Acid Rain Permit Application for the Gateway Generating Station on Wilbur Avenue in Antioch. Gateway Generating Station, formerly Contra Costa Unit 8, was recently acquired by PG&E from Mirant Delta LLC. Mirant obtained an Authority to Construct for two combined cycle combustion turbines and associated equipment from the District in 2001. The ATC was extended in 2003 and 2005 based on substantial use. The ATC is now being transferred to PG&E, which plans to complete construction and bring the generating station online by late 2008.

These new turbine units are subject to the federal Acid Rain Program (40 CFR Parts 72-75). Acid Rain regulations require that the Acid Rain Permit Application be submitted to the appropriate Title V Operating Permit Program authority. The BAAQMD is the delegated Title V permitting authority for the Gateway Generating Station.

If you have any questions regarding these materials, please do not hesitate to call.

Sincerely,

Nancy Matthews
for Gary Rubenstein

Enclosure

cc: Gerardo Rios, EPA Region 9
Tom Allen, PG&E
Jack Keenan, PG&E
Greg Bosscawen, PG&E
Teresa DeBono, PG&E
J. Richard Flander, PG&E

| Gateway Generating Station | | |
|---|---|---|
| Distribution | Copy | Action |
| Director | | |
| Project Manager | | |
| Construction Mgr. | ✓ | ✓ |
| Field Eng. Mech | | |
| Field Eng. Elect | | |
| Project Eng. | ✓ | ✓ |
| APE Mech. | | |
| APE Elect. | | |
| Admin Mgr. | ✓ | ✓ |
| Contracts Mgr. | | |
| Equipment Mgr. | | |
| Compliance Mgr. | | |
| Quality Control | | |
| Safety | | |
| Plant Mgr | | |
| Start-Up Mgr | | |
| | | |
| File No. | 1B2 | 03.14 |

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

# Acid Rain Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31

This submission is: ☑ New ☐ Revised

STEP 1

Identify the source by plant name, State, and ORIS code.

| Plant Name | State | ORIS Code |
|---|---|---|
| Gateway Generating Station | CA | 56476 |

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a." For new units, enter the requested information in columns "c" and "d."

| a | b | c | d |
|---|---|---|---|
| Unit ID# | Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1) | New Units Commence Operation Date | New Units Monitor Certification Deadline |
| GT1 | Yes | 12/1/08 | 6/1/09 |
| GT2 | Yes | 12/1/08 | 6/1/09 |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |
| | Yes | | |

# Acid Rain Program
## Instructions for Acid Rain Permit Application (40 CFR 72.30- 72.31)

*The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the title V permitting authority either issues a permit to the source or disapproves the application.*

Please type or print. The alternate designated representative may sign in lieu of the designated representative. If assistance is needed, contact the title V permitting authority.

**STEP 1** Use the plant name and ORIS Code listed on the Certificate of Representation for the plant. An ORIS code is a 4 digit number assigned by the Energy Information Agency (EIA) at the U.S. Department of Energy to power plants owned by utilities. If the plant is not owned by a utility but has a 5 digit facility code (also assigned by EIA), use the facility code. If no code has been assigned or if there is uncertainty regarding what the code number is, contact EIA at (202) 287-1730 (for ORIS codes), or (202) 287-1927 (for facility codes).

**STEP 2** For column "a," identify each affected unit at the affected source by providing the appropriate unit identification numbers, consistent with the unit identification numbers entered on the Certificate of Representation and with unit identification numbers used in reporting to DOE and/or EIA. For new units without identification numbers, owners and operators may assign such numbers consistent with EIA and DOE requirements.

For columns "c" and "d," enter the commence operation date(s) and monitor certification deadline(s) for new units in accordance with 40 CFR 72.2 and 75.4, respectively.

**Submission Deadlines**

For new units, an initial Acid Rain permit application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority's operating permits regulation.

**Submission Instructions**

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Acid Rain Hotline at (202) 343-9620.

**Paperwork Burden Estimate**

The burden on the public for collecting and reporting information under this request is estimated at 17 hours per response. Send comments regarding this collection of information, including suggestions for reducing the burden, to: Chief, Information Policy Branch (PM-223), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, D.C. 20460; and to: Paperwork Reduction Project (OMB#2060-0258), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. ***Do not submit forms to these addresses; see the submission instructions above.***

Gateway Generating Station
Plant Name (from Step 1)

STEP 3

Read the standard requirements

## Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

## Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

## Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another affected unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

STEP 3, Cont'd.

**Nitrogen Oxides Requirements** The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

**Excess Emissions Requirements**

(1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

**Recordkeeping and Reporting Requirements**

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting
authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

**Liability**

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

| Gateway Generating Station |
|---|
| Plant Name (from Step 1) |

Step 3, Cont'd.

**Liability, Cont'd.**

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 ($NO_x$ averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

**Effect on Other Authorities**

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

**Certification**

Read the certification statement, sign, and date

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

| Name John S. Keenan | |
|---|---|
| Signature John S. Keenan | Date 12/20/06 |

**Air Quality Modeling Results**

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts.

Also shown in Table III are the corresponding significant ambient impact levels listed in Section 233 of the District's NSR Rule. In accordance with Regulation 2-2-414 further analysis is required only for those pollutants for which the modeled impact is above the significant air quality impact level. Further analysis is required for both the one-hour and eight-hour CO concentrations.

**TABLE III**
**Maximum predicted ambient impacts of proposed project ($\mu g/m^3$)**
**[maximums are in bold type]**

| Pollutant | Averaging Time | Commissioning Maximum Impact | Startup | Max. | Start-up (8-hour) | Inversion Break-up Fumigation Impact | Shoreline Fumigation Impact | Significant Air Quality Impact Level |
|---|---|---|---|---|---|---|---|---|
| CO | 1-hour | **3305.3** | 789. | | — | 7.3 | 54.2 | 2000 |
| | 8-hour | **886.7** | 219. | | 227.6 | 6.9 | 17.5 | 500 |

## Background Air Quality Levels

Regulation 2-2-111 entitled "Exemption, PSD Monitoring," exempts an applicant from the requirement of monitoring background concentrations in the impact area (section 414.3) provided the impacts from the proposed project are less than specified levels. Table IV lists the applicable exemption standard and the maximum impact from the proposed facility. As shown, the modeled eight-hour CO impact is above the preconstruction monitoring exemption level. Section 2.4 of Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD) (EPA-450/4-87) states, however, that existing monitoring data may be used if the existing monitor is within or not further than 1 km away from the area of maximum air pollutant concentration from existing sources. To ensure that the maximum background concentrations from exiting sources are used in this analysis, the maximum one- and eight-hour average CO concentrations reported over all BAAQMD monitoring stations from the past four years are listed in Table V.

**TABLE IV**
**PSD monitoring exemption level and maximum impact from the proposed project for CO ($\mu g/m^3$)**

| Pollutant | Averaging Time | Exemption Level | Maximum Impact from Proposed Project |
|---|---|---|---|
| CO | 8- hour | 575 | 886.7 |

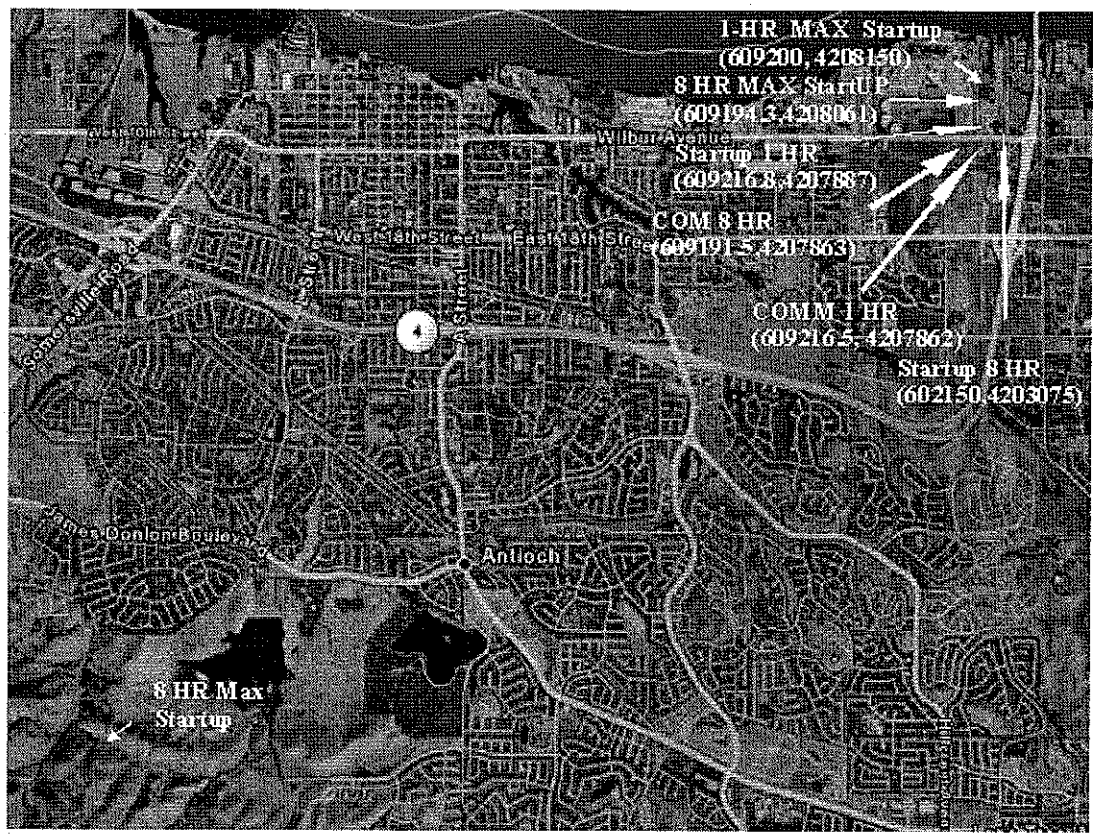


FIGURE 1. Location of project maximum impacts.

**The highest one-hour CO concentration occurred at the Redwood City station in 2007 while the highest eight-hour average CO concentration occurred at the Vallejo-304 Tuolumne Street station in 2004. The eight-hour average concentration were taken from the ADAM Californian Air Resources Board web site (http://www.arb.ca.gov/adam/cgi-bin/db2www/adamtop4b.d2w/start) while the one-hour average concentrations were from the BAAQMD's archive of air quality data (gate1.baaqmd.gov).**

| TABLE V<br>**Background CO (μg/m$^3$) at the Monitoring Station for the Past Four Years (maximum is in bold type)** | | |
|---|---|---|
| Year | CO<br>Highest one-hour | CO<br>Highest 8-hour |
| 2004 | 5039 | **3882** |
| 2005 | 5153 | 3562 |
| 2006 | 5153 | 3367 |
| 2007 | **6299** | 3104 |

Table VI below contains the comparison of the ambient standards with the proposed project impacts added to the maximum background concentrations that required further analysis. The proposed project will not cause an exceedance of the National Ambient Air Quality Standards. The California Ambient Air Quality (CAAQ) Standards will not be exceeded for CO.

**TABLE VI**
**California and national ambient air quality standard and ambient air quality level from the proposed project (μg/m$^3$)**

| Pollutant | Averaging Time | Maximum Background | Maximum Impact from Proposed Project | Maximum combined impact plus maximum background | California Standard | National Standard |
|---|---|---|---|---|---|---|
| CO | 1-hour | 6299 | 3305 | 9604 | 23,000 | 40,000 |
| | 8-hour | 3882 | 887 | 4769 | 10,000 | 10,000 |

***PSD Increment Consumption Analysis***

The EPA has not established PSD increments for CO. Therefore, this analysis is not required.

**CLASS I PSD INCREMENT ANALYSIS**

EPA requires an increment analysis of any PSD source within 100 km of a Class I area which increases $NO_2$ or $PM_{10}$ concentrations by 1 μg/m$^3$ or more (24-hour average) inside the Class I area. This analysis is not required as Point Reyes National Seashore is located roughly 81.2 km southwest of the project and the facility is applying offsets so that there is no increase in $NO_2$ or $PM_{10}$.

## VISIBILITY, SOILS AND VEGETATION IMPACT ANALYSIS

Visibility impacts were not investigated because there was no net increase in PM or $NO_2$ emissions.

Maximum project CO concentrations would be less than all of the applicable State and national primary and secondary ambient air quality standards, which are designed to protect the public welfare form any known or anticipated effects, including plant damage. Therefore, the facility's impact on soils and vegetation would be insignificant.

**CONCLUSIONS**

The results of the air quality impact analysis indicate that the proposed project would not interfere with the attainment or maintenance of applicable AAQS for CO. The analysis was based on EPA approved models and calculation procedures and was performed in accordance with Section 414 of the District's NSR Rule.

Appendix C

# Health Risk Assessment Results

**INTEROFFICE MEMORANDUM**
May 20, 2008

TO: Brian Lusher
FROM: Irma Salinas/Jane Lundquist

Via: Scott B. Lutz
Daphne Y. Chong

SUBJECT: Health Risk Assessment for PG&E Gateway Generating Station, Antioch, Plant #18143, Application #17182, Two Gas Turbine Generators and One Fire Pump Diesel Engine

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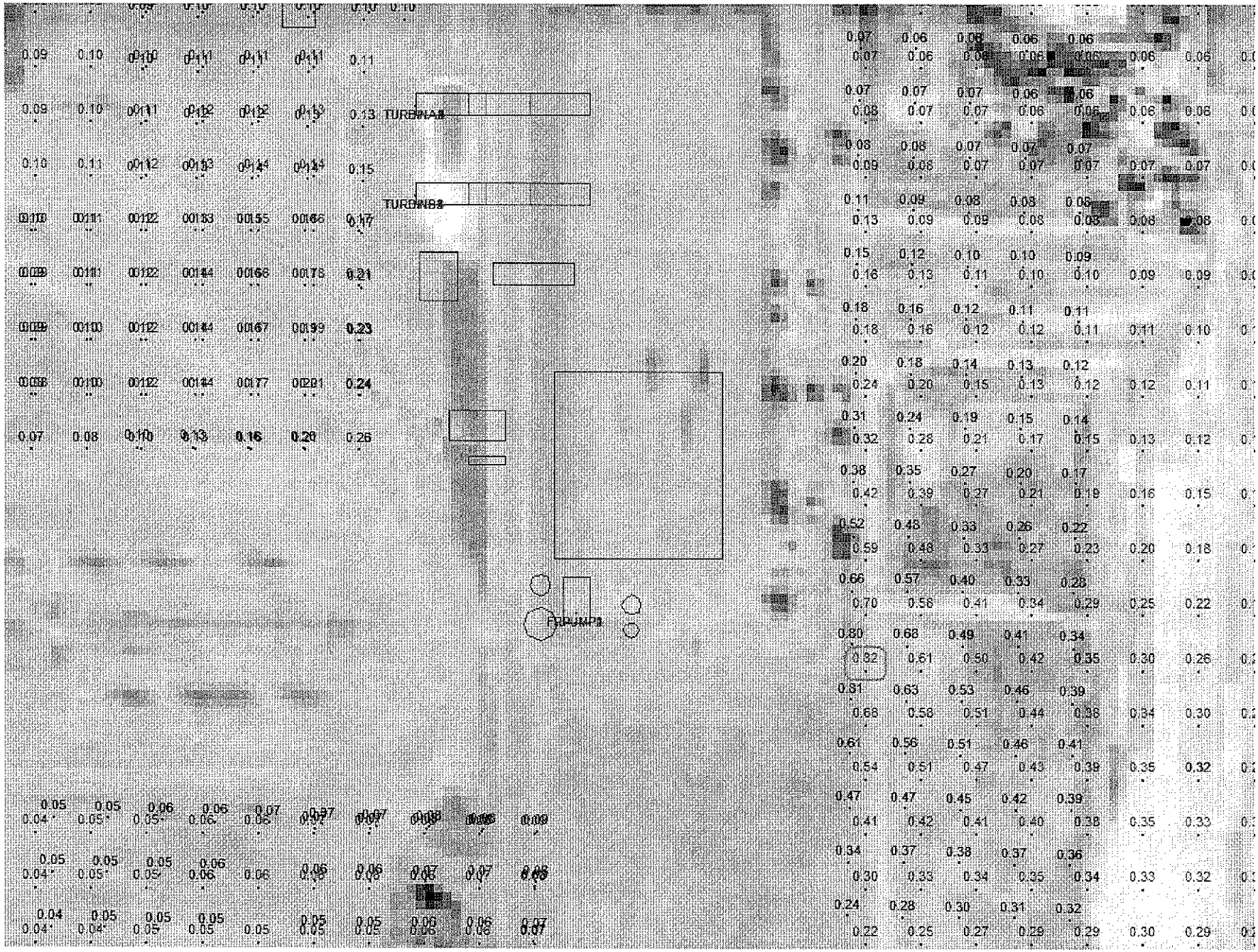
We have completed a health risk assessment for the above referenced permit application. The analysis estimates the incremental health risk resulting from toxic air contaminant (TAC) emissions from two gas turbine generators and one fire pump diesel engine. Results from the health risk assessment indicate that, for this project, the maximum incremental cancer risk is estimated at **0.8 in a million**, the chronic hazard index is **0.03**, and the acute hazard index is **0.06**. In accordance with the District's Regulation 2, Rule 5, these risk levels are considered acceptable.

*EMISSIONS:* The health risk value weighted emissions were entered into the model so that the modeled results are in terms of cancer risk, chronic hazard index and acute hazard index. The attached Table 1 shows the TAC emission rates, health values and health value weighted emission used in this analysis. The chronic and acute weighted emissions for hazard indices were conservatively calculated summing all weighted emissions regardless of the target organ that is affected by the pollutant. Acrolein was not included in this analysis. The District currently does not conduct a HRSA for emissions of acrolein because CARB does not have certified emission factors or an analytical test method for acrolein and thus the appropriate tools needed to implement and enforce acrolein emission limits are not available.

*MODELING:* AERMOD atmospheric dispersion model runs were executed to estimate the chronic and acute health risks. The meteorological data, terrain data, source and building parameters that were used in the PSD analysis for this project were also used in this health risk assessment.

*HEALTH RISK:* The health risk assessment was performed in accordance with the California Office of Environmental Health Hazard Assessment (OEHHA) guidelines. PAH as benzo(a)pyrene, which is a multipathway substance, was also evaluated for non-inhalation pathway exposures (soil ingestion and dermal exposure). The health risk results are presented below.

| Receptor | NAD27 UTM_E | NAD27 UTM_N | Cancer Risk in a million | Year | Comment |
|---|---|---|---|---|---|
| Resident | 609975 | 4207550 | 0.38 | 2006 | Agricultural area assumed to be residential |
| Resident | 609975 | 4207550 | 0.41 | 2005 | Agricultural area assumed to be residential |
| Resident | 609900 | 4207550 | 0.36 | 2004 | Agricultural area assumed to be residential |
| Worker | 609200 | 4208000 | 0.80 | 2006 | East fence line near fire pump |
| Worker | 609200 | 4208000 | **0.82** | 2005 | East fence line near fire pump |
| Worker | 609193.3 | 4207987 | 0.78 | 2004 | East fence line near fire pump |
| | | | **Chronic HI** | | |
| Resident | 609975 | 4207550 | 0.026 | 2006 | Agricultural area assumed to be residential |
| Resident | 609975 | 4207550 | **0.028** | 2005 | Agricultural area assumed to be residential |
| Resident | 609925 | 4207550 | 0.025 | 2004 | Agricultural area assumed to be residential |
| Worker | 609725 | 4207775 | 0.007 | 2006 | Near Highway 160 and Wilbur Ave |
| Worker | 609725 | 4207750 | 0.008 | 2005 | Near Highway 160 and Wilbur Ave |
| Worker | 609600 | 4207825 | 0.007 | 2004 | Near Highway 160 and Wilbur Ave |
| | | | **Acute HI** | | |
| Receptor | 609290.1 | 4207762 | 0.042 | 2006 | Near southeast fence line |
| Receptor | 609241.1 | 4207837 | **0.056** | 2005 | Southeast fence line |
| Receptor | 609265.8 | 4207812 | 0.055 | 2004 | Near southeast fence line |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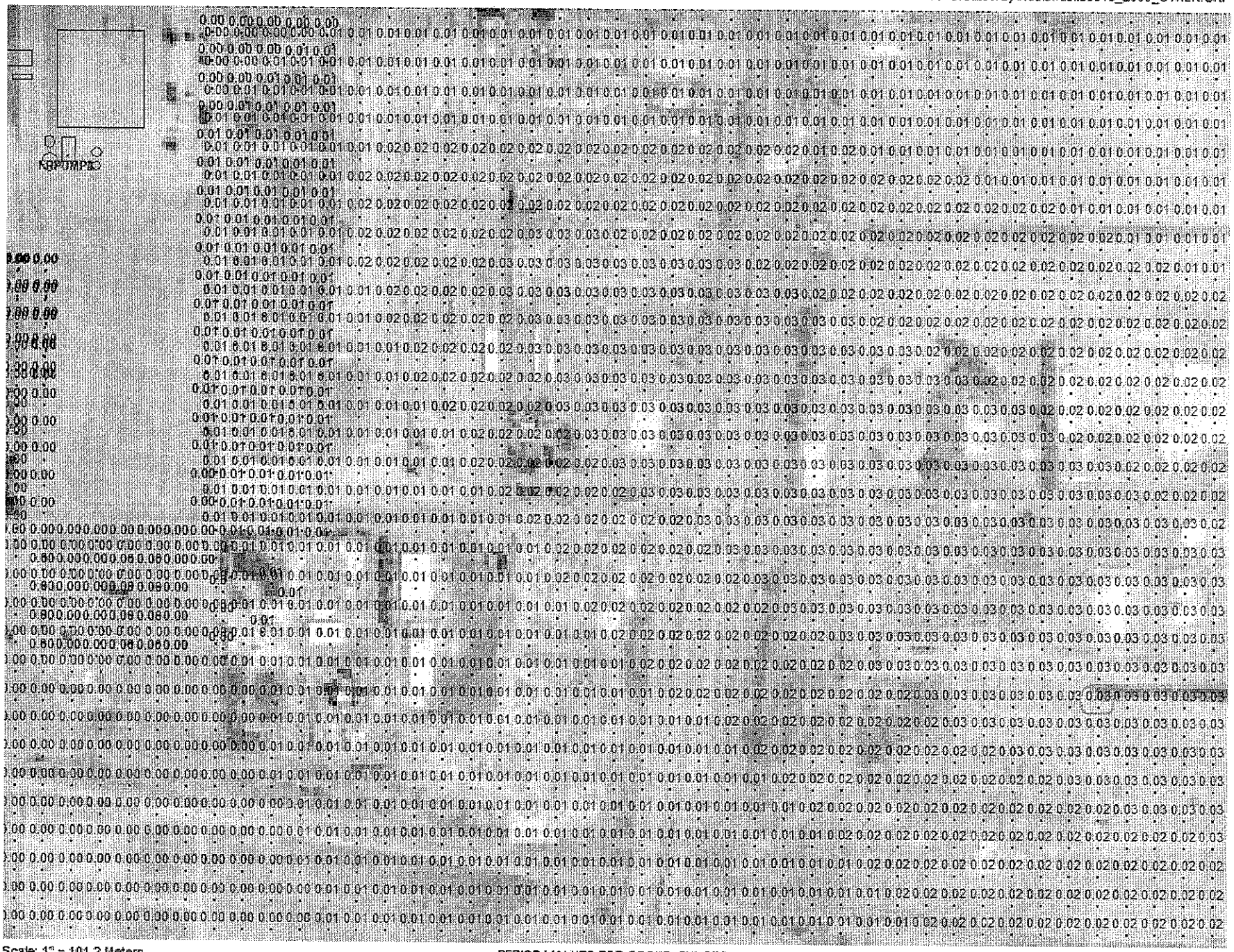
TURBINB2
PRPUMP2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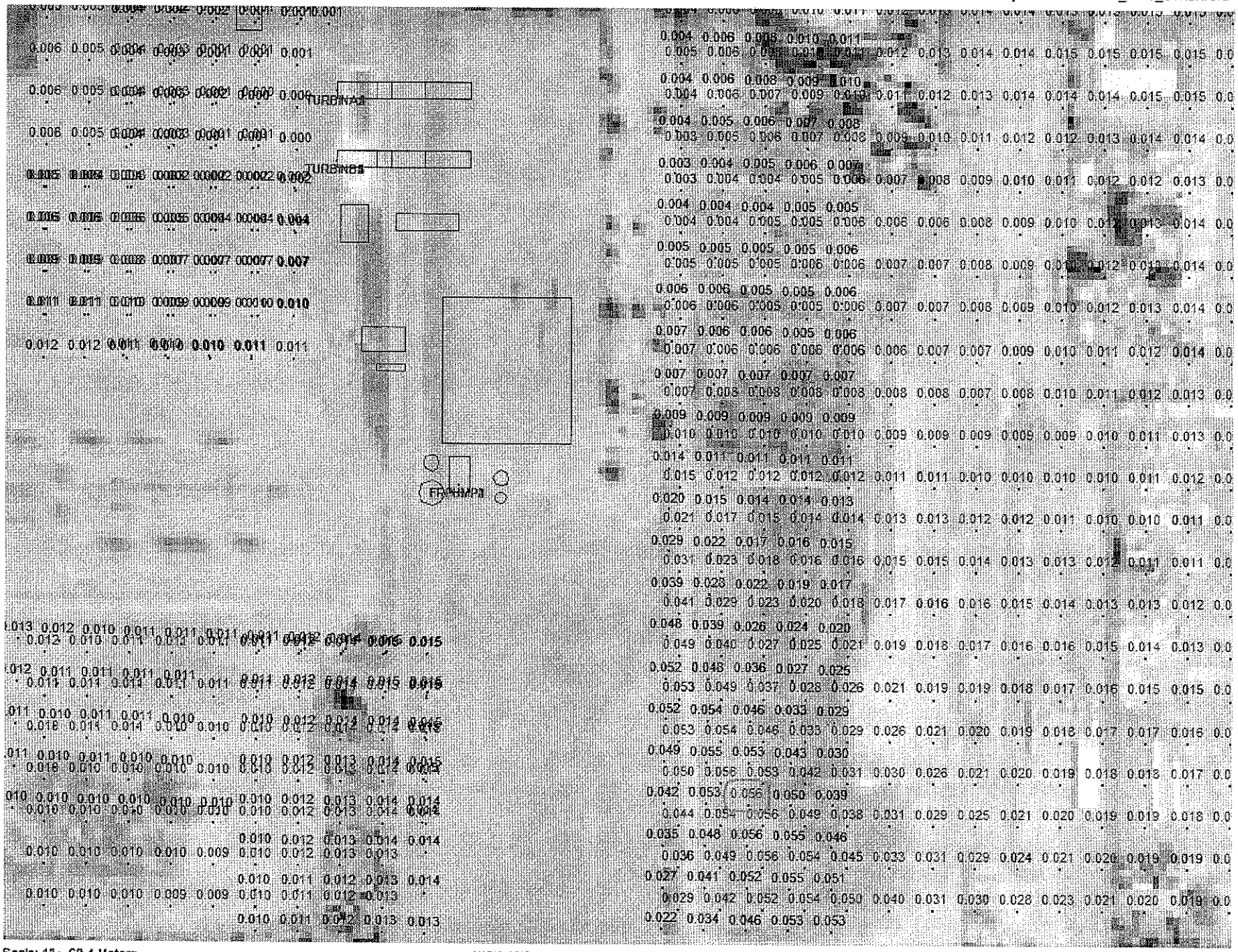
TURBINA2
TURBINB2
FFPUMP2

Input File - C:\riskscreens\Gateway\HealthRisks0519_2005_OTHER.DTA
Output File - C:\riskscreens\Gateway\HealthRisks0519_2005_OTHER.LST
Met File - C:\riskscreens\Gateway\GATEA05.SFC

*** AERMOD - VERSION 07026 *** *** Gateway HRA impacts P# 18143 A# 17182
*** 05/19/08
***
*** 14:48:43

*** MODEL SETUP OPTIONS SUMMARY ***

- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -

**Model Is Setup For Calculation of Average CONCentration Values.
-- DEPOSITION LOGIC --
**Model Uses NO DRY DEPLETION. DDPLETE = F
**Model Uses NO WET DEPLETION. WDPLETE = F
**NO GAS DRY DEPOSITION Data Provided.
**Model Uses RURAL Dispersion Only.
**Model Uses Regulatory DEFAULT Options:
1. Stack-tip Downwash.
2. Model Accounts for ELEVated Terrain Effects.
3. Use Calms Processing Routine.
4. Use Missing Data Processing Routine.
5. No Exponential Decay
**Model Assumes No FLAGPOLE Receptor Heights.
**Model Calculates 1 Short Term Average(s) of: 1-HR
and Calculates PERIOD Averages
**This Run Includes: 14 Source(s); 19 Source Group(s); and 10861 Receptor(s)
**Misc. Inputs: Base Elev. for Pot. Temp. Profile (m MSL) = 3.00 ; Decay Coef. = 0.000
; Rot. Angle = 0.0

*** POINT SOURCE DATA ***

| SOURCE ID | NUMBER PART. CATS. | EMISSION RATE (GRAMS/SEC) | X (METERS) | Y (METERS) | BASE ELEV. (METERS) | STACK HEIGHT (METERS) | STACK TEMP. (DEG.K) | STACK EXIT VEL. (M/SEC) | STACK DIAMETER (METERS) | BLDG EXISTS | URBAN SOURCE | CAP/ HOR | EMIS RATE SCALAR VARY BY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TURBINA1 | 0 | 0.22600E+01 | 608996.0 | 4208257.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINA2 | 0 | 0.19200E+00 | 608996.0 | 4208257.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINA3 | 0 | 0.50700E+00 | 608996.0 | 4208257.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINA4 | 0 | 0.44700E-01 | 608996.0 | 4208257.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINA5 | 0 | 0.58000E-02 | 608996.0 | 4208257.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINB1 | 0 | 0.22600E+01 | 608996.0 | 4208216.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINB2 | 0 | 0.19200E+00 | 608996.0 | 4208216.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINB3 | 0 | 0.50700E+00 | 608996.0 | 4208216.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINB4 | 0 | 0.44700E-01 | 608996.0 | 4208216.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| TURBINB5 | 0 | 0.58000E-02 | 608996.0 | 4208216.5 | 4.3 | 59.44 | 355.22 | 19.92 | 5.11 | YES | NO | NO | |
| FRPUMP1 | 0 | 0.19000E-01 | 609069.0 | 4208026.0 | 4.3 | 3.40 | 683.00 | 44.10 | 0.15 | YES | NO | NO | |
| FRPUMP2 | 0 | 0.11400E-04 | 609069.0 | 4208026.0 | 4.3 | 3.40 | 683.00 | 44.10 | 0.15 | YES | NO | NO | |
| FRPUMP3 | 0 | 0.15700E-01 | 609069.0 | 4208026.0 | 4.3 | 3.40 | 683.00 | 44.10 | 0.15 | YES | NO | NO | |
| FRPUMP4 | 0 | 0.11200E-04 | 609069.0 | 4208026.0 | 4.3 | 3.40 | 683.00 | 44.10 | 0.15 | YES | NO | NO | |

# Exhibit No. 320

BAAQMD Proposed Approval of Amended Authority to Construct and PSD Permit, dated 6/4/2008

# Engineering Evaluation
# For Proposed Amended Authority to Construct
# And
# Draft PSD Permit

## Gateway Generating Station
Antioch, CA

Bay Area Air Quality Management District
Application 17182

June 2008

Brian K. Lusher
Air Quality Engineer II

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# I Background

This is the Engineering Evaluation for the proposed amended Authority to Construct and Draft PSD Permit for the Gateway Generating Station (GGS). The GGS is a proposed 530-MW, natural-gas fired, combined-cycle merchant power plant, originally proposed by Mirant Delta, LLC as Contra Costa Unit No. 8, to be located at 3223 Wilbur Avenue in Antioch, CA. The project was originally certified by the California Energy Commission (CEC) on May 30, 2001. (The Engineering Evaluation/Determination of Compliance that was prepared at that time is incorporated in this document by reference.) The Authority to Construct was issued by the Bay Area Air Quality Management District (District) on July 24, 2001. The project was originally proposed by Mirant Delta, LLC and has since been acquired by Pacific Gas & Electric (PG&E) Company in late 2006. The CEC transferred the license for the project to PG&E. The District transferred the Authority to Construct for the project to PG&E. PG&E has evaluated the project as originally permitted and requested an amendment to the CEC license and the Authority to Construct. Permit Application No. 17182 is considered a major modification to a major source per Regulation 2-2-405 due to an increase in carbon monoxide emissions from the proposed amended Authority to Construct and proposed draft PSD permit. The document is required to be subject to a 30 day public comment period in accordance with Regulation 2-2-405 and the PSD regulations and the PSD delegation agreement.

The amendment of the Authority to Construct consists of:

- Replacing the wet cooling tower and replacing it with a dry cooling system.
- Reducing hourly emission rates of $NO_x$ (as NO2), CO, and $PM_{10}$ during normal operations to levels consistent with current Best Available Control Technology (BACT) levels for similar projects.
- Increasing startup emissions estimates based on data from facilities using identical turbines.
- Reducing the maximum hourly emissions of CO during startup to 900 lb/hour.
- Increasing the daily CO permit limit for the facility.
- Increasing annual CO permit limits for the facility based on data from facilities using identical turbines.
- Increasing the allowable commissioning emissions for the gas turbines and heat recovery steam generators (HRSGs).
- Replace the natural gas fired preheater with a smaller unit that is exempt from District permit requirements.

- Add a 300 HP Diesel Fire Pump engine to the facility.

The GGS will consist of two natural gas fired General Electric Frame 7FA combustion turbine generators (CTGs), one steam turbine generator (STG) and associated equipment, two supplementally fired heat recovery steam generators (HRSGs), a dry cooling system, a natural gas fired preheater, an oil water separator, and a 300 hp diesel fire pump engine.

This document is the engineering evaluation of the proposed amended BAAQMD Authority to Construct application number 17182. The document is also the statement of basis for the draft Prevention of Significant Deterioration (PSD) permit for the facility.

The document describes how the proposed GGS will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review (NSR) regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

Although the proposed Authority to Construct and draft PSD permit is an amendment to an existing Authority to Construct and PSD permit, the District has evaluated the project as a whole for compliance with applicable regulatory requirements, including elements that are covered under the existing permit and are not being changed.

The proposed amended Authority to Construct and draft PSD permit are subject to the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407 and 40 C.F.R. sections 124.10 through 124.12. Interested members of the public are being provided a 30-day comment period during which they may review the proposed permit, the Engineering Evaluation, and all supporting materials and submit comments on any relevant issues. The District will consider any comments it received before issuing an amended Authority to Construct and Draft PSD Permit.

# II Project Description

## 1. Permitted Equipment

PG&E is proposing a combined-cycle combustion turbine power generation facility with a nominal electrical output of 530 MW. As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 175 MW and the steam produced by the heat recovery steam generators (HRSGs) will feed to a steam turbine generator with a rated electrical output of 192 MW.

The GGS will consist of the following permitted equipment:

S-41 Combustion Turbine Generator (CTG) #1, General Electric Frame 7FA Model PG 7231 or equivalent, 1872 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-42 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 395 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-43 Combustion Turbine Generator (CTG) #2, General Electric Frame 7FA Model PG 7231 or equivalent, 1872 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-44 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 395 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-45 Natural Gas-fired Fuel Preheater (Exempt per Regulation 2-1-114)

S-46 Dry Cooling System (Exempt per 2-1-103)

S-47 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input

S-48 Oil-Water Separator, Highland Tank, HTC, 8000 gallon

## 2. Equipment Operating Scenarios

*Turbines and Heat Recovery Steam Generators*

Because GGS will be a merchant power plant, the exact operation of the new gas turbine/HRSG power trains will be dictated by market circumstances and demand. However, the following general operating modes are expected to occur at the GGS:

| | |
|---|---|
| *Base Load:* | Maximum continuous output with duct firing |
| *Load Following:* | Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario |
| *Partial Shutdown:* | Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during periods of low overall demand such as late evening and early morning hours |
| *Full Shutdown:* | May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation |

The table below outlines the maximum operating annual air pollutant emissions for this project. The carbon monoxide emissions have increased from 259.1 tons/year to 554.3 tons/year and the $PM_{10}$ emissions have decreased slightly from 112.2 tons/year to 101.4 tons/year. Sulfur Oxides emissions have decreased slightly from 48.5 tons/year to 37.0 tons/year.

**TABLE 1. MAXIMUM ANNUAL REGULATED CRITERIA AIR POLLUTANT EMISSIONS FOR THE FACILITY.**

| | $NO_2$ (ton/yr) | CO (ton/yr) | POC (ton/yr) | $PM_{10}$ (ton/yr) | $SO_2$ (ton/yr) |
|---|---|---|---|---|---|
| **Original Limits** | **174.3** | **259.1** | **46.6** | **112.2** | **48.5** |
| **New Limits** | **174.3** | **554.3** | **46.6** | **101.7** | **37.0** |

Original Limits are from Application No. 1000. The New Limits are for the revised Authority to Construct for this project. Emissions from Dewpoint Heater are not included in the new permit limits since the heater is exempt per Regulation 2, Rule 1, Section 114.

## 3. Air Pollution Control Strategies and Equipment

The proposed GGS includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (Regulation 2, Rule 2) for emissions of nitrogen oxides ($NO_x$ as $NO_2$), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide ($SO_2$), and particulate matter of less than 10 microns in diameter[1] ($PM_{10}$).

### a. Selective Catalytic Reduction with Ammonia Injection for the Control of $NO_x$

The gas turbines and HRSG duct burners each trigger BACT for $NO_x$ emissions. The gas turbines will be equipped with dry low-$NO_x$ (DLN) combustors, which minimize $NO_x$ emissions by lowering peak flame temperature by premixing combustion air with a lean fuel mixture. The HRSGs will be equipped with low-$NO_x$ duct burners, which are designed to minimize $NO_x$ emissions. In addition, the combined $NO_x$ emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT level $NO_x$ emission limit of 2.0 ppmvd @ 15% $O_2$ (one hour average).

### b. Oxidation Catalyst, Dry Low-$NO_x$ (DLN) Combustors and Good Combustion Practices to control and minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-$NO_x$ combustors, which operate on a lean fuel mixture that

[1] A subset of $PM_{10}$ that has recently come under heightened regulatory scrutiny is particulate matter of less than 2.5 microns in diameter ($PM_{2.5}$). The majority of the particulate matter emitted from the GGP will have a diameter of less than 1 micron, and so it will be both $PM_{10}$ and $PM_{2.5}$. The analysis in this document regarding $PM_{10}$ is therefore equally applicable to $PM_{2.5}$.

minimizes incomplete combustion and CO emissions. The HRSGs will be equipped with low-$NO_x$ duct burners which are also designed to minimize CO emissions. Furthermore, the gas turbines and HRSGs will be abated by oxidation catalysts which will oxidize the CO emissions to produce $CO_2$ and water. The gas turbine and HRSG duct burner combined exhaust will achieve a CO emission limit of 4.0 ppmvd @ 15% $O_2$ (three hour average).

### c. Oxidation Catalyst, Dry Low-$NO_x$ (DLN) Combustors and Good Combustion Practices to control and minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-$NO_x$ combustors which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with low-$NO_x$ burners, which are designed to minimize incomplete combustion and therefore minimize POC emissions. Furthermore, the turbines and HRSGs will be abated by oxidation catalysts which will also reduce POC emissions. The gas turbine and HRSG duct burner combined exhaust will achieve a POC emission limit of 2.0 ppmvd @ 15% $O_2$ (one hour average) which corresponds to an 0.00256 lb/MMBtu emission factor.

### d. Exclusive Use of Clean-burning Natural gas to Minimize $SO_2$ and $PM_{10}$ Emissions

The gas turbines and HRSG duct burners will burn exclusively PUC-regulated natural gas to minimize $SO_2$ and $PM_{10}$ emissions. Because the $SO_2$ emission rate is proportional to the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of "low sulfur content" natural gas will result in the lowest possible emission of $SO_2$. $PM_{10}$ emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

**TABLE 2. SUMMARY OF CONTROL STRATEGIES AND EMISSION LIMITATIONS FOR GAS TURBINES AND HRSG DUCT BURNERS**

| Source | Control Strategy and Emission Limit[a] | | | | |
|---|---|---|---|---|---|
| | $NO_x$ | CO | POC | $PM_{10}$ | $SO_2$ |
| Gas Turbine & HRSG Power Trains | DLN Combustors/SCR | DLN Combustors/ Oxidation Catalyst | DLN Combustors/ Oxidation Catalyst | PUC-Regulated Natural Gas | PUC-Regulated Natural Gas |
| | 2.0 ppmv (1 hour average) | 4.0 ppmv (3 hour average) | 2.0 ppmv (1 hour average) | 12.0 lb/hr | 5.86 lb/hr |

[a] ppmv concentrations dry at 15% $O_2$

# III Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant (TAC) emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

**Table 3** is a summary of the daily maximum regulated air pollutant emissions for the permitted sources at GGS. These emission rates are used to determine if the BACT requirement of the District New Source Review regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that has the potential to emit 10 pounds or more per highest day of POC, NPOC, $NO_x$, $SO_2$, $PM_{10}$, or CO are subject to the BACT requirement for that pollutant.

**TABLE 3. MAXIMUM DAILY REGULATED AIR POLLUTANT EMISSIONS FOR FACILITY.**

| Source | Pollutant (lb/day) | | | | |
|---|---|---|---|---|---|
| | Nitrogen Oxides (as $NO_2$) | Carbon Monoxide | Precursor Organic Compounds | Particulate Matter ($PM_{10}$) | Sulfur Dioxide |
| Total Gas Turbines and HRSGs[a,b] | 1746.5 | 11465.6 | 382.4 | 576.0 | 282 |
| Fire Pump Engine | 2.86 | 0.39 | 0.15 | 0.074 | 0.004 |
| Total Permitted Equipment (nonexempt)[c] | 1749.4 | 11466.0 | 382.6 | 576.1 | 282 |

[a] $NO_x$, CO, and POC emission rates are based upon one 360 minute cold start-up and 18 hours of Gas Turbine /HRSG full load operation at maximum combined firing rate of 2094.4 MM BTU/hr in one day; $PM_{10}$ and $SO_2$ emission rates are based upon 24 hours of Gas Turbine/HRSG operation at maximum combined firing rate of 2,094.4 MM BTU/hr in one day

[b] emission rates based upon 24 hr/day operation at maximum emission rates; see Appendices for emissions calculations

[c] emission rates based upon 1 hr/day for engine testing.

**Table 4** is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 10.0 ppmvd @ 15% $O_2$ due to ammonia slip from the A-1 and A-3 SCR Systems. The chronic and acute screening trigger levels shown are per Table 2-5.1 of Regulation 2, Rule 5.

## TABLE 4. MAXIMUM FACILITY TOXIC AIR CONTAMINANT (TAC) EMISSIONS

| Toxic Air Contaminant | Project lb/hour | Project lb/year | Acute Risk Screening Trigger Level (lb/hr) | Chronic Risk Screening Trigger Level (lb/yr) |
|---|---|---|---|---|
| 1,3-Butadiene | 5.22E-04 | 4.35E+00 | None | 1.10E+00 |
| Acetaldehyde | 5.63E-01 | 4.69E+03 | None | 6.40E+01 |
| Acrolein | 7.76E-02 | 6.47E+02 | 4.20E-04 | 2.30E+00 |
| Ammonia | 5.86E+01 | 4.89E+05 | 7.10E+00 | 7.70E+03 |
| Benzene | 5.46E-02 | 4.55E+02 | 2.90E+00 | 6.40E+00 |
| Benzo(a)anthracene | 9.28E-05 | 7.73E-01 | None | None |
| Benzo(a)pyrene | 5.71E-05 | 4.76E-01 | None | 1.10E-02 |
| Benzo(b)fluoranthene | 4.64E-05 | 3.87E-01 | None | None |
| Benzo(k)fluoranthene | 4.52E-05 | 3.76E-01 | None | None |
| Chrysene | 1.03E-04 | 8.62E-01 | None | None |
| Dibenz(a,h)anthracene | 9.65E-05 | 8.04E-01 | None | None |
| Ethylbenzene | 7.35E-02 | 6.12E+02 | None | 7.70E+04 |
| Formaldehyde | 1.88E+00 | 1.57E+04 | 2.10E-01 | 3.00E+01 |
| Hexane | 1.06E+00 | 8.86E+03 | None | 2.70E+05 |
| Indeno(1,2,3-cd)pyrene | 9.65E-05 | 8.04E-01 | None | None |
| Naphthalene | 6.82E-03 | 5.68E+01 | None | None |
| Propylene | 3.17E+00 | 2.64E+04 | None | 1.20E+05 |
| Propylene Oxide | 1.96E-01 | 1.64E+03 | 6.80E+00 | 4.90E+01 |
| Toluene | 2.92E-01 | 2.43E+03 | 8.20E+01 | 1.20E+04 |
| Xylene (Total) | 1.07E-01 | 8.93E+02 | 4.90E+01 | 2.70E+04 |
| Diesel Particulate Matter | 7.40E-02 | 3.70E+00 | None | 5.80E-01 |
| Benzo(a)pyrene equivalents | 1.88E-04 | 1.56E+00 | None | 1.10E-02 |

Table 5 is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of any of the trigger levels shown must perform modeling to assess the net air quality impact of the proposed facility.

**TABLE 5. MAXIMUM ANNUAL FACILITY REGULATED AIR POLLUTANT EMISSIONS**

| Pollutant | Permitted Source Emissions[a,b] (tons/year) | PSD Trigger[c] (tons/year) |
|---|---|---|
| Nitrogen Oxides (as $NO_2$) | 174.3 | 100 |
| Carbon Monoxide | 554.3 | 100 |
| Precursor Organic Compounds | 46.6 | N/A[d] |
| Particulate Matter ($PM_{10}$) | 101.7 | 100 |
| Sulfur Dioxide[e] | 37.0 | 100 |

[a] emission increases from proposed gas turbines and heat recovery steam generators, and fire pump diesel engine; specified as permit condition limit
[b] includes start-up and shutdown emissions for gas turbines
[c] for a new major facility
[d] there is no PSD requirement for POC since the BAAQMD is designated as nonattainment for the federal ambient air quality standard for ozone.
[e] Annual emissions are calculated based on annual average sulfur content of 0.75 grain per 100 scf in natural gas

**The sulfuric acid mist ($H_2SO_4$) emissions** from the Gateway Generating Station are estimated to be less than the PSD threshold of 7 tons per year. The applicant will conduct source testing to measure $SO_2$, $SO_3$, $H_2SO_4$ and ammonium sulfates. This testing is necessary because the conversion in turbines of fuel sulfur to $SO_3$, and then to $H_2SO_4$ is not well established. The applicant will estimate emissions of $H_2SO_4$ from the facility using heat input and lb/MMBtu emission factors developed during periodic source testing.

# IV Statement of Compliance

The following section summarizes the applicable District, state and federal rules and regulations and describes how the proposed Gateway Generating Station will comply with those requirements.

**Regulation 2, Rule 2; New Source Review**

The primary requirements of New Source Review that apply to the proposed GGS facility are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2-302; "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR", and Section 2-2-404, "PSD Air Quality Analysis".

1. Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT[2] is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source: or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO, or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

[2] 40 C.F.R. Section 52.21 contains a substantively identical BACT requirement. The District's BACT analysis satisfies both District and federal regulatory requirements.

## Gas Turbines and HRSGs

The following section includes BACT determinations by pollutant for the gas turbines and HRSG duct burners of the proposed GGS Project. Because each Gas Turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

### Nitrogen Oxides ($NO_x$)

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT 1 (technologically feasible/cost-effective) for $NO_x$ for a combined cycle gas turbine with a rated output $\geq$ 40 MW as 2.0 ppmvd @ 15% $O_2$ averaged over one hour, typically achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with dry low-$NO_x$ combustors. The EPA has accepted this BACT determination as federal LAER. This BACT determination has been imposed on recent BAAQMD permits issued for: East Altamont Energy Center (Application #2589), Pico Power Project (Application #6481), and Russell City Energy Center (Application #15487). In addition, Palomar Energy Project located in San Diego County, a 546 MW combined cycle power plant, recently started up (4/1/06) with a $NO_x$ emission requirement of 2.0 ppmvd, @ 15% $O_2$, averaged over one hour.

  A $NO_x$ emission concentration of 2.0 ppmvd, @ 15% $O_2$, averaged over one hour, has been established as "achieved-in-practice" BACT for $NO_x$ based upon our review of CEM data for the ANP Blackstone power plant, a nominal 550-MW combined cycle facility. The ANP Blackstone power plant is located in Blackstone, Massachusetts and consists of two ABB GT-4 Gas Turbines rated at 180-MW each with unfired heat recovery steam generators. We reviewed CEM data for approximately 2,313 firing hours for unit 1 and 2,737 firing hours for unit 2 which occurred from April 2001 to April 2002. With the exception of start-up and shutdown periods, the NOx concentrations were below the 2.0 ppmvd limit by a sufficient margin to demonstrate consistent, continuous compliance.

  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a $NO_x$ emission concentration limit of 2.0 ppmvd $NO_x$ @ 15% $O_2$, averaged over one hour during all operating modes except gas turbine start-ups and shutdowns. This meets the current District BACT 1 determination and meets or exceeds the current EPA and ARB BACT determinations for $NO_x$. Compliance with this emission limitation will be achieved through the use of dry low-$NO_x$ combustors which utilize "lean-premixed" combustion technology to reduce the formation of $NO_x$ and CO. The $NO_x$ emissions from the turbine and HRSG will be abated through the use of a selective catalytic reduction (SCR) system with ammonia injection. The $NO_x$ emission concentration will be verified by a CEM (continuous emissions monitor) located at the common stack for each gas turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

Supplemental heat will be supplied to the HRSGs with low-$NO_x$ duct burners, which are designed to minimize $NO_x$ emissions. The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve $NO_x$ emission concentrations of less than or equal to 2.0 ppmvd @ 15% $O_2$, averaged over one hour.

***Top-Down BACT Analysis***

The following "top-down" BACT analysis for $NO_x$ has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual. A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. Although this analysis is based upon a controlled $NO_x$ emission concentration of 2.5 ppmv instead of the applicable $NO_x$ emission rate of 2.0 ppmv, the District has determined that the conclusions of the analysis are applicable to this project.

***Available Control Options and Technical Feasibility***

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the $SCONO_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for $NO_x$ of 2.5 ppmvd @ 15% $O_2$, averaged over one hour or 2.0 ppmvd @ 15% $O_2$, averaged over three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, has conducted "full-scale damper testing" that demonstrates that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the GGS Project. Stone & Webster Management Consultants, Inc. of Denver, Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve reliability and leakage problems observed with early SCONOx units. The previous concerns regarding reliability and leakage problems are reported to be resolved. The District will continue to monitor operating issues and reliability of sites utilizing SCONOx technology.

The control technology originally called SCONOx is now called EMx™ and has several licensees. The technology has been installed on several gas turbine installations and the technology appears to be improving in both performance and cost effectiveness.

The feasibility of the "scale-up" of the EMx system for large gas turbines (GE Frame 7FA) has not been demonstrated.

The District considers either SCR or EMx to be a acceptable control technologies for this project. The District would support the use of EMx technology if the applicant proposed to use it for this project.
We are providing the following analysis for informational purposes only. The analysis shown in Table 6 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a

$NO_x$ emission rate of 25 ppmvd @ 15% $O_2$. The following text discusses SCONOx which is now called EMx technology.

**TABLE 6. TOP DOWN BACT ANALYSIS SUMMARY FOR $NO_X$**

| Control Alternative | Emissions[a] (ton/yr) | Emission Reduction[b] (ton/yr) | Total Annualized Cost[c] ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) | Toxic Impacts | Adverse Environmental Impacts | Incremental Energy Impact (MM BTU/yr) |
|---|---|---|---|---|---|---|---|---|
| $SCONO_x$ | 788 | 709 | 4,122,889 | 5,815 | N/A[d] | No | No | 122,000[e] |
| SCR | 788 | 709 | 1,557,125 | 2,196 | - | Yes | No | 67,900[e] |

[a] based upon uncontrolled $NO_x$ emission rate of 25 ppmvd @ 15% $O_2$, and annual firing rate of 17,436,780 MM BTU/yr

[b] based upon $NO_x$ emission rate after abatement of 2.5 ppmvd @ 15% $O_2$, and annual firing rate of 17,436,780 MM BTU/yr

[c] "Cost Analysis for $NO_x$ Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d] does not apply since there is no difference in emission reduction quantity between alternatives

[e] "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

*Energy Impacts*

As shown in Table 6, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

*Economic Impacts*

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 6, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of $NO_x$ abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although $SCONO_x$ will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendices for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for $NO_x$ of 2.0 ppmvd @ 15% $O_2$, averaged over one hour and therefore achieve the same $NO_x$ emission reduction in tons per year.

*Environmental Impacts*

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 10 ppmvd @ 15% $O_2$. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.056 and a chronic hazard index of 0.028 resulting from the emission of all non-carcinogenic compounds, including ammonia, from the gas turbines. In accordance with the District Regulation 2, Rule 5 and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the BAAQMD. The potential impact on the formation of secondary particulate matter in the SJVAPCD is not known. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The GGS will utilize aqueous ammonia in a 19% (by weight) solution. Consequently, the GGS will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases of ammonia. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed GGS facility and found that the impact would not be significant. Therefore, the potential environmental impact due to aqueous ammonia storage at the GGS does not justify the elimination of SCR as a control alternative.

The use of $SCONO_x$ will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

*Conclusion*

Both SCR and EMx ($SCONO_x$) can achieve the current accepted BACT/LAER specification for $NO_x$ without causing significant energy, economic, or environmental impacts. Thus, neither can be eliminated as a viable control alternative. The only aspect of this analysis affected by the current $NO_x$ BACT standard of 2.0 ppmvd @ 15% $O_2$, averaged over one hour is the cost of compliance. The increased cost of control for each technology is not expected to affect the conclusion of this analysis. Therefore, the applicant's proposed use of SCR to meet the $NO_x$ BACT/LAER specification is acceptable.

**Carbon Monoxide (CO)**

BACT for CO will be analyzed within the context of two distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for CO for combined cycle gas turbines with a rated output of $\geq$ 50 MW as a CO emission concentration of $\leq$ 4.0 ppmvd @ 15% $O_2$. This BACT specification is based upon the Sacramento Power Authority (Campbell Soup facility) located in Sacramento County, California. BACT 1 (technologically feasible/cost-effective) is currently not specified. This emission rate limit applies to all operating modes except gas turbine start-up and shutdown.

The applicant has agreed to a CO emission limit of 4.0 ppmvd @ 15% $O_2$, averaged over any rolling 3-hour period. This satisfies the current BACT 2 limitation as discussed above. Compliance with this emission limitation will be achieved through the use of dry low-$NO_x$ combustors which utilize "lean-premixed" combustion technology to reduce the formation of $NO_x$ and CO. CO emissions from the turbine and HRSG will be abated through the use of an oxidation catalyst. The CO emission concentration will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

**Precursor Organic Compounds (POCs)**

- Combustion Gas Turbines

There currently is no BACT 1 (technologically feasible/cost-effective) specification for POC for this source category. Currently, District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for POC for combined cycle gas turbines with an output rating $\geq$ 50 MW as 2.0 ppmv, dry @ 15% $O_2$, which is typically achieved through the use of dry-low $NO_x$ combustors and/or an oxidation catalyst. This is based upon the Delta Energy Center and Metcalf Energy Center, which were recently permitted at a POC emission limit of 2.0 ppmvd @ 15% $O_2$.

The applicant has agreed to not exceed a POC stack concentration of 2.0 ppmvd @ 15% $O_2$ with the use of dry-low $NO_x$ combustors and/or an oxidation catalyst. Thus the GGS satisfies the BACT requirement for POC emissions.

- Heat Recovery Steam Generators (HRSGs)

  The HRSG duct burners will be of low-$NO_x$ design, which minimizes incomplete combustion and therefore the POC emission rate. Each gas turbine/HRSG pair will achieve this emission limitation through the use of dry low-$NO_x$ burners, good combustion practices and an oxidation catalyst.

**Sulfur Dioxide ($SO_2$)**

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for $SO_2$ for combined cycle gas turbines with an output rating of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. This corresponds to an $SO_2$ emission factor of 0.0028 lb/MM BTU. The proposed turbines will burn exclusively PUC-regulated natural gas with an expected average sulfur content of 0.75 grains per 100 scf, which will result in minimal $SO_2$ emissions. This meets the current BACT 2 specification for $SO_2$.

- Heat Recovery Steam Generators (HRSGs)

  As is the case of the Gas Turbines, BACT for $SO_2$ for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.75 grains per 100 scf. This meets the current BACT 2 specification for $SO_2$.

**Particulate Matter ($PM_{10}$)**

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT for $PM_{10}$ for combined cycle gas turbines with rated output of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf. The proposed turbines will utilize exclusively PUC-regulated natural gas with an average sulfur content of 0.75 gr/100 scf, which will result in minimal direct $PM_{10}$ emissions and minimal formation of secondary $PM_{10}$ such as ammonium sulfate.

- Heat Recovery Steam Generators (HRSGs)

  BACT for $PM_{10}$ for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf. The HRSGs

will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.75 grains per 100 scf which will result in minimal direct $PM_{10}$ emissions and minimal formation of secondary $PM_{10}$ such as ammonium sulfate.

**Fire Pump Diesel Engine**

Based upon 24 hour per day operation under emergency conditions, the proposed fire pump diesel engine triggers BACT for $NO_x$, POC, and CO, since its potential to emit for each of those pollutants exceeds 10 pounds per day. The current District BACT limits and the specifications for the proposed engine are summarized in Table 7. The applicant will be required by permit conditions to select and install an engine that satisfies BACT for all pollutants listed.

**TABLE 7. DISTRICT BACT LIMITS AND FIRE PUMP ENGINE SPECIFICATIONS**

| Pollutant | District BACT Specifications[a] (g/bhp-hr) | S-6 Engine[b] Specifications (g/bhp-hr) |
|---|---|---|
| $NO_x$ (as $NO_2$) | 6.9 | 4.32 |
| CO | 2.75 | 0.597 |
| POC | 1.5 | 0.227 |
| $SO_2$ | Ultra-Low Sulfur Oil | 0.0055[c] |
| $PM_{10}$ | Ultra-Low Sulfur Oil | 0.112[c] |

[a] BACT 2 ("achieved in practice") per District BACT Guideline 96.1.2, "IC Engine – Compression Ignition ≥ 175 hp output rating"
[b] emission rates specified by applicant
[c] permit conditions will require the use of ultra-low sulfur oil (15 ppm by weight) at S-47 engine

**Emission Offsets**

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and $NO_x$ (as $NO_2$) emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 35 tons per year of $NO_x$ (as $NO_2$), offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of $NO_x$.

Pursuant to Regulation 2-2-303, offsets are required for PM10 and SO2 emission increases from permitted sources at facilities that will emit more than 1 ton per year since 1991 (although offsets are voluntary if the increases are less than 100 tons per year).

**Timing for Provision of Offsets**

Pursuant to District Regulation 2-2-311, the applicant surrendered the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct on May 14, 2003. Pursuant to District Regulation 2, Rule 3, "Power

Plants," the Authority to Construct was issued after the California Energy Commission issued the Certificate for the proposed power plant.

**Offset Requirements by Pollutant**

The applicable offset ratios and the quantity of offsets required are summarized in Table 8.

POC Offsets

Because the GGS will emit less than 35 tons of POC per year, the POC emissions were offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302.

$NO_x$ Offsets

Because the GGS will emit greater than 35 tons per year of Nitrogen Oxides ($NO_x$) from permitted sources, the applicant provided emission reduction credits (ERCs) of $NO_x$ at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. Pursuant to District Regulation, 2-2-302.2, the applicant provided POC ERCs to offset the proposed $NO_x$ emission increases at a ratio of 1.15 to 1.0.

$PM_{10}$ Offsets

Because the total $PM_{10}$ emissions from permitted sources will exceed 100 tons per year, the GGS does trigger the $PM_{10}$ offset requirement of District Regulation 2-2-303.

$SO_2$ Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed $SO_2$ emission increases associated with this project since the facility $SO_2$ emissions will not exceed 100 tons per year. Regulation 2-2-303 allows for the voluntary offsetting of $SO_2$ emission increases of less than 100 tons per year. The applicant has opted not to provide such emission offsets.

## Offset Package

**Table 8** summarizes the offset obligation of the GGS. The emission reduction credits presented in Table 8 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, "Emissions Banking", and were subsequently issued as banking certificates by the BAAQMD under the applications cited in the table footnotes. If the quantity of offsets issued under any certificate exceeded 35 tons per year for any pollutant, the application was required to fulfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

As indicated below, PG&E has surrendered valid emission reduction credits to offset the emission increases from the permitted sources proposed for the GGS project.

### TABLE 8. EMISSION REDUCTION CREDITS SURRENDERED (TON/YR)

| | POC[a] | $NO_x$[b] | $PM_{10}$[c] |
|---|---|---|---|
| Valid Emission Reduction Credits | 53.6 | 200.5 | 112.2 |
| Permitted Source Emission Limits | 46.6 | 174.3 | 101.7 |
| Offsets Required per BAAQMD Calculations | 53.6[d] | 200.5[d] | 101.7 |

[a]From Banking Certificate # 693.

[b]From Banking Certificate # 693.

[c]$SO_2$ used at a ratio of 3:1. The following $SO_2$ Banking Certificates used:

#693 321.90 tons

#694 14.53 tons

#695 0.17 tons

**Total** **336.60 tons** ($PM_{10}$ equivalent 112.2 tons)

[d]Reflects applicable offset ratio of 1.15:1.0 pursuant to Regulation 2-2-302

[e]Reflects applicable offset ratio of 1.0:1.0 pursuant to Regulation 2-2-303

These Banking Certificates originated from the following locations:

| Certificate | Company | Location | Original Issue Dates |
|---|---|---|---|
| #693 | Gaylord Container | Antioch | 6/8/84, 3/12/90, 7/15/93 |
| #694 | P G & E | Martinez | 7/22/87 |
| #695 | Hudson ICS | San Leandro | 4/9/97 |

## PSD Air Quality Impact Analysis

The proposed amended Authority to Construct and draft PSD permit for the GGS project triggers the PSD air quality impact analysis requirements of 40 C.F.R. section 52.21 and District regulations for Carbon Monoxide, only. A PSD Air Quality Impact anaylsis for NOx and PM10

was conducted during the original permit proceeding in 2001. The District implements the federal PSD requirement pursuant to a Delegation Agreement with EPA Region IX.

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts from CO emissions due to the GGS project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the GGS facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for $NO_2$, CO, and $PM_{10}$ or an exceedance of any applicable PSD increment.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation. The entire PSD air quality impact analysis is contained in Appendix B (Memo dated May 29, 2008 prepared by Irma Salinas, Air Toxics Section).

Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit $H_2SO_4$ at rates in excess of 38 lb/day and 7 tons per year.

The sulfuric acid mist ($H_2SO_4$) emissions from the Gateway Generating Station are estimated to be less than the PSD threshold of 7 tons per year. The applicant will conduct source testing to measure $SO_2$, $SO_3$, $H_2SO_4$ and ammonium sulfates. This testing is necessary because the conversion in turbines of fuel sulfur to $SO_3$, and then to $H_2SO_4$ is not well established. The applicant will estimate emissions of $H_2SO_4$ from the facility using heat input and lb/MMBtu emission factors developed during the source testing.

**TABLE 9. MAXIMUM PREDICTED AMBIENT IMPACTS OF PROPOSED GGS ($\mu G/M^3$).**

| Pollutant | Averaging Time | Commissioning Maximum Impact | Start-up | Inversion Break-up Fumigation Impact | Shoreline Fumigation Impact | Modeled Impact | Significant Air Quality Impact Level |
|---|---|---|---|---|---|---|---|
| CO | 1-hour | **3305.3** | 789.0 | 7.3 | 54.2 | 38.6 | 2000 |
| | 8-hour | **886.7** | 219.6 | 6.9 | 17.5 | 8.1 | 500 |

The maximum modeled project impacts for 1-hour & 8-hour average CO exceeded their corresponding significance levels for air quality impacts per Regulation 2-2-233, further analysis to determine if the corresponding ambient air quality standards will be exceeded per District regulation 2-2-414 was performed. Table 10 summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution from the proposed GGS for CO 1-hour and 8-hour impacts that exceeded the significance level. As shown in Table 10, the worst-case CO emissions from GGS will not cause or contribute to an exceedance of the California ambient air quality standards for 1-hour and 8-hr CO.

**TABLE 10. APPLICABLE CALIFORNIA AND NATIONAL AMBIENT AIR QUALITY STANDARDS (AAQS) AND AMBIENT AIR QUALITY LEVELS FROM THE PROPOSED GGS ($\mu G/M^3$)**

| Pollutant | Averaging Time | Maximum Background | Maximum Project impact | Maximum Project impact plus maximum background | California Standards | National Standards |
|---|---|---|---|---|---|---|
| CO | 1-hour | 6299 | 3305 | 9604 | 23,000 | 40,000 |
| | 8-hour | 3882 | 887 | 4769 | 10,000 | 10,000 |

**Health Risk Assessment**

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be conducted to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the GGS project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the GGS are summarized in Table 11. In accordance with the requirements of the BAAQMD Regulation 2-5 and Office of Health Hazard Assessment (OEHHA) guidelines, the impact on public health due to the emission of these compounds was assessed utilizing EPA approved air pollutant dispersion models.

**TABLE 11. HEALTH RISK ASSESSMENT RESULTS**

| Receptor | Cancer Risk (risk in one million) | Chronic Non-Cancer Hazard Index (risk in one million) | Acute Non-Cancer Hazard Index (risk in one million) |
|---|---|---|---|
| Maximally Exposed Individual | 0.82 | 0.028 | 0.056 |
| Resident | 0.41 | 0.028 | 0.056 |
| Worker | 0.82 | 0.008 | 0.056 |

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to BAAQMD Regulation 2-5, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. The chronic hazard index and the acute hazard index attributed to the emission of non-carcinogenic air contaminants is each considered to be not significant since each is less than 1.0. Therefore, the GGS facility is deemed to be in compliance with BAAQMD Regulation 2-5. Please see Appendix C (Memo dated May 29, 2008 prepared by Irma Salinas and Jane Lundquist, Air Toxics Section) for further discussion.

## Other Applicable District Rules and Regulations

### Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis ensures that the proposed facility will comply with this Regulation by concluding that the Gateway Generating Station will not interfere with the attainment or maintenance of applicable federal or state health-based ambient air quality standards for $NO_2$, CO and $PM_{10}$.

### Regulation 2, Rule 1, Sections 301 and 302: Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the GGS has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for all sources at the GGS facility.

### Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-403, the Final Determination of Compliance (FDOC) prepared in 2001 served as the APCO's decision that the proposed power plant will meet the requirements of all applicable District, state, and federal regulations. The FDOC prepared in 2001 contained proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-304, the PDOC was subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The issuance of the FDOC was not considered a final determination of whether the facility can be constructed or operated.

This document serves as the proposed amended Authority to Construct and draft Draft PSD Permit for the project. The CEC is not undertaking a formal licensing proceeding for the amendment, and so the District is not preparing a Determination of Compliance for use by the CEC.

### Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants

A risk screening analysis was performed to estimate the health risk resulting from the toxic air contaminant (TAC) emissions from the GGS. Results from this analysis indicate that the maximally exposed individual cancer risk is estimated at 0.82 in a million, the chronic non-cancer hazard index at 0.028 in a million, and acute non-cancer hazard index at 0.056 in million. Therefore the GGS will be in compliance the requirements of Regulation 2-5-301. Furthermore, the proposed controls are considered to be toxic best available control technology (TBACT).

**Regulation 2, Rule 6: Major Facility Review**

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the GGS shall submit an application to the District for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Regulation 2-6-212.1 and 2-6-218, the GGS will become subject to Regulation 2, Rule 6 upon completion of construction as demonstrated by first firing of the gas turbines.

**Regulation 2, Rule 7: Acid Rain**

The GGS gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. The applicant has submitted a Title IV permit application pursuant to Regulation 2, Rule 7 and 40 C.F.R. Part 72.

**Regulation 6: Particulate Matter and Visible Emissions**

Through the use of dry low-$NO_x$ burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines, HRSG duct burners, auxiliary boiler, and emergency generator set is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the operation of each power train (Gas Turbine and HRSG Duct Burners) is 0.0013 gr/dscf @ 6% $O_2$. See Appendices for CTG/HRSG grain loading calculations.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. However, the California Energy Commission has imposed requirements for construction activities including the use of water and/or chemical dust suppressants to minimize $PM_{10}$ emissions and prevent visible particulate emissions.

**Regulation 7: Odorous Substances**

Regulation 7-302 prohibits the discharge of odorous substances which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia slip emissions from the proposed CTG/HRSG power trains will each be limited by permit condition to 10 ppmvd @ 15% $O_2$, the facility is expected to comply with the requirements of Regulation 7.

**Regulation 8: Organic Compounds**

The gas turbines and HRSG duct burners are exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at those sources. The fire pump diesel engine will comply with Regulation 8-2-301 since its emissions will contain a total carbon concentration of less than 300 ppmv, dry.

The use of solvents for cleaning and maintenance at the GGS is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

**Regulation 9: Inorganic Gaseous Pollutants**

Regulation 9, Rule 1, Sulfur Dioxide

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level $SO_2$ concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits $SO_2$ emissions in excess of 300 ppmv (dry). With maximum projected $SO_2$ emissions of < 1 ppmv, the gas turbines, HRSG duct burners, and fire pump engine are not expected to cause ground level $SO_2$ concentrations in excess of the limits specified in Regulation 9-1-301 and should easily comply with section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The proposed combustion gas turbines (each rated at 1872 MM BTU/hr, HHV) and HRSG duct burners (each rated at 395 MM BTU/hr, HHV) shall comply with the Regulation 9-3-303 $NO_x$ limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.0 ppmvd @ 15% $O_2$. The proposed fire pump diesel engine is not subject to this regulation since it has a maximum heat input rating of approximately 2 MM BTU/hr, based upon a maximum rated output of 300 bhp.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed S-42 & S-44 HRSGs are subject to the emission concentration limits of Regulation 9, Rule 7, section 301 which limits $NO_x$ emissions to 30 ppmv, dry @ 3% $O_2$ and CO emissions to 400 ppmv, dry @ 3% $O_2$. To determine if the HRSG duct burners comply with these $NO_x$ emission limits, it would be necessary to install a $NO_x$ CEM upstream of the HRSG duct burners since the HRSGs and turbines exhaust through a common stack. Because the combined exhaust from the turbines and HRSGs are subject to a much more stringent BACT limit of 2.0 ppmvd @ 15% $O_2$, it is reasonable to conclude that the HRSG duct burners comply with the emission limits of Regulation 9, Rule 7. As a practical matter, the HRSG duct burners are therefore subject to Regulation 9, Rule 9.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines

The proposed 300 hp fire pump diesel engine is exempt from Sections 301, 302 and 502 of Regulation 9, Rule 8 per Regulation 9-8-110.3 until 2012, since it will be fired exclusively on diesel fuel. After 2012, the engine will meet the emissions limitations in Section 9-8-304. The proposed emergency generator will comply with Regulation 9-8-330 which allows emergency use for unlimited hours, and limits non-emergency use to 50 hours per year.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the proposed combustion gas turbines will be limited by permit condition to $NO_x$ emissions of 2.0 ppmvd @ 15% $O_2$, they will comply with the Regulation 9-9-301.3 $NO_x$ limitation of 9 ppmvd @ 15% $O_2$.

Regulation 10: Standards of Performance for New Stationary Sources

Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60. The applicable subparts of 40 CFR Part 60 include Subpart A, "General Provisions", Subpart Da, "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978", Subpart KKKK "Standards of Performance for Stationary Gas Turbines" and Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The proposed gas turbines and heat recovery steam generators comply with all applicable standards and limits proscribed by these regulations. The applicable emission limitations are summarized below:

| Source | Requirement | Emission Limitation | Compliance Verification |
|---|---|---|---|
| Gas Turbines and HRSGs | Subpart Da | | |
| | 40 CFR 60.44a(a)(1) | 0.2 lb $NO_x$/MM BTU, except during start-up, shutdown, or malfunction | Sources limited by permit condition to 0.0074 lb $NO_x$/MM BTU |
| | 40 CFR 60.44a(a)(2) | 25% reduction of potential $NO_x$ emission concentration | SCR Systems will comply with this reduction requirement |
| | 40 CFR 60.44a(d)(1) | 1.6 lb $NO_x$/MW-hr | 0.08 lb $NO_x$/MW-hr at nominal plant rating of 530 MW |
| | Subpart GG | Not Applicable | |
| | Subpart KKKK | 0.39 lb $NO_x$/MW-hr, 0.59 lb $SO_2$/MW-hr | 0.08 lb $NO_x$/MW-hr, 0.03 lb $SO_2$/MW-hr |
| Fire pump Diesel Engine | Subpart IIII | | |
| | | 7.8 NMHC+$NO_x$, 2.6 CO, 0.40 $PM_{10}$ (g/HP-hr) for 2008 and earlier engines | S-47 Fire pump Engine will comply with required emission limits. |

## State Requirements

GGS is subject to the Air Toxic "Hot Spots" Program contained in the California Health and Safety Code Section 44300 et seq. The facility will prepare inventory plans and reports as required.

The Fire Pump Engine is subject to and will be in compliance with the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines contained in Title 17 of the California Code of Regulations Section 93115. The allowable operating hours and recordkeeping requirements contained in the ATCM will be included in the Permit Conditions.

# V Permit Conditions

The District is proposing the following permit conditions to ensure that the proposed project complies with all applicable District, state, and federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb/hr and lb/MM BTU of natural gas fired) will insure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and $NO_x$ limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up, shutdown and combustor tuning. If the CO and $NO_x$ CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable $O_2$ content and the differing response times of the $O_2$ and $NO_x$ monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, $SO_2$, and $PM_{10}$ mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to steady-state operation of each CTG/HRSG power train, the District is proposing conditions that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and/or oxidation catalysts in place. Commissioning activities include, but are not limited to, the testing of the gas turbines, adjustment of control systems, and the cleaning of the HRSG steam tubes. Permit conditions 1 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedance of any applicable short-term ambient air quality standard.

## Gateway Generating Station Permit Conditions

Definitions:

1-hour period: Any continuous 60-minute period beginning on the hour.
Calendar Day: Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year: Any consecutive twelve-month period of time
Heat Input: All heat inputs refer to the heat input at the higher heating value fuel.
Rolling 3-hour period: Any three-hour period that begins on the hour and does not include start-up or shutdown periods.
Firing Hours: Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments.
MM Btu: million British thermal units
Gas Turbine Start-up Mode: The lesser of the first 360 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d).
Gas Turbine Shutdown Mode: The lesser of the 60 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(a) through 20(d) until termination of fuel flow to the Gas Turbine.
Specified PAHs: The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.
Benzo[a]anthracene
Benzo[b]fluoranthene
Benzo[k]fluoranthene
Benzo[a]pyrene
Dibenzo[a,h]anthracene
Indeno[1,2,3-cd]pyrene
Corrected Concentration: The concentration of any pollutant (generally $NO_x$, CO, or $NH_3$) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% $O_2$ by volume on a dry basis.
Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the GGS construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.
Commissioning Period: The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The

period shall terminate when the plant has completed performance testing and is available for commercial operation.

Combustor Tuning Activities: All testing, adjustment, tuning, and calibration activities recommended by the gas turbine manufacturer or an independent qualified contractor to insure safe and reliable steady state operation of the gas turbines. This includes, but is not limited to, adjusting the amount of fuel distributed between the combustion turbine's staged fuel systems to simultaneously minimize $NO_x$ and CO production while minimizing combustor dynamics and ensuring combustor stability.

Combustor Tuning Period: The period, not to exceed 360 minutes, during which gas turbine combustor tuning activities are taking place.

Precursor Organic Compounds (POCs): Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate

CEC CPM: California Energy Commission Compliance Program Manager

GGS: Gateway Generating Station

Applicability:

Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 43 shall apply after the commissioning period has ended. Conditions 44 through 47 shall apply at all times.

Conditions for the Commissioning Period

1. The owner/operator of the GGS shall minimize emissions of carbon monoxide and nitrogen oxides from S-41 and S-43 Gas Turbines and S-42 and S-44 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-41 & S-43 Gas Turbine combustors and S-42 & S-44 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-11 and A-13 SCR Systems and A-12 and A-14 CO Oxidation Catalyst Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-41 & S-43 Gas Turbines and S-42 & S-44 Heat Recovery Steam Generators.

4. Coincident with the as designed operation of A-11 & A-13 SCR Systems, pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall comply with the $NO_x$ and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the GGS shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired dewpoint heater. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-$NO_x$ combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and $NO_x$ continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

6. During the commissioning period, the owner/operator of the GGS shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

- firing hours for each gas turbine and each HRSG
- fuel flow rates to each train
- stack gas nitrogen oxide emission concentrations at P-11 and P-12
- stack gas carbon monoxide emission concentrations P-11 and P-12
- stack gas carbon dioxide or oxygen concentrations P-11 and P-12

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44). The owner/operator shall use District-approved methods to calculate heat input rates, $NO_x$ mass emission rates, carbon monoxide mass emission rates, and $NO_x$ and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous emission monitors specified in condition 6 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44). After first firing of the turbines, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and $NO_x$ emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-41 Gas Turbine and S-42 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-11 SCR System and/or A-12 Oxidation Catalyst System shall not exceed 300 hours during the commissioning period. Such operation of S-41 Gas Turbine and S-42 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

9. The total number of firing hours of S-43 Gas Turbine and S-44 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-13 SCR System and/or A-14 Oxidation Catalyst System shall not exceed 300 hours during the commissioning period. Such operation of S-43 Gas Turbine and S-44 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, $PM_{10}$, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

11. Combined pollutant mass emissions from the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-41 & S-43).

| | | |
|---|---|---|
| $NO_x$ (as $NO_2$) | 8,400 pounds/calendar day | 400 pounds/hour |
| CO | 40,000 pounds/calendar day | 4,000 pounds/hour |
| POC(as $CH_4$) | 1,600 pounds/calendar day | |
| $PM_{10}$ | 432 pounds/calendar day | |
| $SO_2$ | 297 pounds/calendar day | |

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 21. The source test shall determine $NO_x$, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-41 & S-43) and the Heat Recovery Steam Generators (HRSGs; S-42 & S-44)

13. The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on PUC quality natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. The owner/operator of GGS shall sample the natural gas from each supply source on a quarterly basis to determine the sulfur content of the gas using a District approved analytical procedure. PG&E sulfur data may be used to track the sulfur content in the natural gas delivered to GGS provided that such data can be demonstrated to be representative of the natural gas supplied to GGS. (BACT for $SO_2$ and $PM_{10}$)

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,094.4 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for $NO_x$)

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 49,950 MM Btu per calendar day. (PSD for $PM_{10}$)

16. The combined cumulative heat input rate for the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall not exceed 34,900,000 MM Btu per year. (Offsets)

17. The HRSG duct burners (S-42 and S-44) shall not be fired unless its associated Gas Turbine (S-41 and S-43, respectively) is in operation. (BACT for $NO_x$)

18. Except as provided in Condition No. 8, S-41 Gas Turbine and S-42 HRSG shall be abated by the properly operated and properly maintained A-11 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-11 catalyst bed has reached minimum operating temperature. (BACT for $NO_x$)

19. Except as provided in Condition No. 9, S-43 Gas Turbine and S-44 HRSG shall be abated by the properly operated and properly maintained A-13 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-13 catalyst bed has reached minimum operating temperature. (BACT for $NO_x$)

20. The Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S- 44) shall comply with requirements (a) through (i) under all operating scenarios, including duct burner firing mode. Requirements (a) through (i) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Regulation 2, Rule 5)

(a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as $NO_2$) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed 15.2 pounds per hour or 0.0072 lb/MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as $NO_2$) at P-12 (the combined exhaust point for the S-43 Gas

Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed 15.2 pounds per hour or 0.0072 lb./MM Btu (HHV) of natural gas fired. (PSD for $NO_x$)
(b) The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any 1-hour period. (BACT for $NO_x$)
(c) Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed 0.0088 lb/MM Btu (HHV) of natural gas fired or 18.5 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)
(d) The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed 4.0 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any rolling 3-hour period. (BACT for CO)
(e) Ammonia ($NH_3$) emission concentrations at P-11 and P-12 each shall not exceed 10.0 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (Regulation 2, Rule 5 for $NH_3$)
(f) Precursor organic compound (POC) mass emissions (as CH4) at P-11 and P-12 each shall not exceed 5.3 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)
(g) Sulfur dioxide ($SO_2$) mass emissions at P-11 and P-12 each shall not exceed 5.92 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)
(h) Particulate matter ($PM_{10}$) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or 0.0095 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter ($PM_{10}$) mass emissions at P-11 and P-12 each shall not exceed 12 pounds per hour or 0.0065 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)
(i) Compliance with the hourly $NO_x$ emission limitations specified in condition 20(a) and 20(b) shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the owner/operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average $NO_x$ concentration exceeds 2.0 ppmv, dry @ 15% $O_2$. Examples of transient load conditions include, but are not limited to the following:

(1) Initiation/shutdown of combustion turbine inlet air cooling
(2) Rapid combustion turbine load changes
(3) Initiation/shutdown of HRSG duct burners

The maximum 1-hour average $NO_x$ concentration for periods that include short-term excursions shall not exceed 30.0 ppmv, dry @ 15% $O_2$. All emissions during short-term excursions shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-41 and S-43) during a start- up or a shutdown or during a combustor tuning period shall not exceed the limits established below. (PSD)

| | Start-Up or Combustor Tuning Period (lb/period) | Startup/Shutdown (lb/hr) |
|---|---|---|
| Oxides of Nitrogen (as $NO_2$) | 600 | 160 |
| Carbon Monoxide (CO) | 5,400 | 900 |
| Precursor Organic Compounds (as CH4) | 96 | 16 |

22. The Gas Turbines (S-41 and S-43) shall not be in start-up mode simultaneously. (PSD)

23. Total combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44), including emissions generated during Gas Turbine start-ups, shutdowns and combustor tuning periods shall not exceed the following limits during any calendar day:

(a) 1,746.5 pounds of $NO_x$ (as $NO_2$) per day (CEQA)
(b) 11,465.6 pounds of CO per day (PSD)
(c) 382.4 pounds of POC (as CH4) per day (CEQA)
(d) 576 pounds of $PM_{10}$ per day (PSD)
(e) 282 pounds of $SO_2$ per day (BACT)

24. Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44) and the Diesel Fire Pump Engine (S-48), including emissions generated during gas turbine start-ups, shutdowns and combustor tuning periods shall not exceed the following limits during any consecutive twelve-month period:

(a) 174.3 tons of $NO_x$ (as $NO_2$) per year (Offsets, PSD)
(b) 554.3 tons of CO per year (Cumulative Increase)
(c) 46.6 tons of POC (as $CH_4$) per year (Offsets)
(d) 101.7 tons of $PM_{10}$ per year (Offsets, PSD)
(e) 37.0 tons of $SO_2$ per year (Cumulative Increase)

25. Toxic Air Contaminant and HAP Emission Limits

The maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limits:

15,700 pounds of formaldehyde per year
455 pounds of benzene per year
1.56 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the

satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 10.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (Regulation 2, Rule 5)

26. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 20(i), 21, 23(a), 23(b), 24(a), and 24(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up, Shutdown and Combustor Tuning periods) for all of the following parameters:
(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(b) Carbon Dioxide ($CO_2$) or Oxygen ($O_2$) concentrations, Nitrogen Oxides ($NO_x$) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.
(c) Ammonia injection rate at A-11 and A-13 SCR Systems
The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and average hourly pollutant emission concentrations. The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:
(d) Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(e) Corrected $NO_x$ concentrations, $NO_x$ mass emissions (as $NO_2$), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.
Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and 26(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:
(f) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.
(g) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-41, S-42, S-43, and S-44) combined.
(h) the average $NO_x$ mass emissions (as $NO_2$), CO mass emissions, and corrected $NO_x$ and CO emission concentrations for every clock hour and for every rolling 3-hour period.
(i) on an hourly basis, the cumulative total $NO_x$ mass emissions (as $NO_2$) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.
(j) For each calendar day, the average hourly Heat Input Rates, Corrected $NO_x$ emission concentrations, $NO_x$ mass emissions (as $NO_2$), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.
(k) on a daily basis, the cumulative total $NO_x$ mass emissions (as $NO_2$) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.
(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c) through 23(e)., and 24(c) through 24(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter ($PM_{10}$) mass emissions (including condensable particulate matter), and Sulfur Dioxide ($SO_2$) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 26, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:
(a) For each calendar day, POC, $PM_{10}$, and $SO_2$ emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-41, S-42, S-43, and S-44) combined.
(b) on a daily basis, the 365 day rolling average cumulative total POC, $PM_{10}$, and $SO_2$ mass emissions, for all four sources (S-41, S-42, S-43, and S-44) combined.
(Offsets, PSD, Cumulative Increase)

28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of Formaldehyde, Benzene, and Specified PAHs. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 34,900,000 MM Btu/year and the highest emission factor (pounds of pollutant per MM Btu of Heat Input) determined by any source test of the S-41 & S-43 Gas Turbines and/or S-42 & S-44 Heat Recovery Steam Generators. If this calculation method results in an unrealistic mass emission rate (the highest emission factor occurs at a low firing rate) the applicant may use an alternate calculation, subject to District approval. (Regulation 2, Rule 5)

29. Within 60 days of start-up of the GGS, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 to determine the corrected ammonia ($NH_3$) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding $NH_3$ emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve $NO_x$ emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the $NH_3$ source testing on an annual basis thereafter. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (Regulation 2, Rule 5)

30. Within 60 days of start-up of the GGS and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor

organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as $NO_2$), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter ($PM_{10}$) emissions including condensable particulate matter. Within 60 days of start up of the GGS and for two additional years there after, the owner/operator shall conduct a District approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine the emissions of H2SO4, SO3, and ammonium sulfate. (BACT, offsets, PSD, Regulation 2, Rule 5)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total $PM_{10}$ emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 60 days of start-up of the GGS and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 28 for any of the compounds listed below are less than the BAAQMD Regulation 2, Rule 5 trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

| | | |
|---|---|---|
| Benzene | less than or equal | 6.4 pounds/year |
| Formaldehyde | less than or equal | 30 pounds/year |
| Specified PAHs | less than or equal | 1.56 pounds/year |

(Regulation 2, Rule 5)

33. The owner/operator of the GGS shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

34. The owner/operator of the GGS shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

35. The owner/operator of the GGS shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

36. The stack height of emission points P-11 and P-12 shall each be at least 195 feet above grade level at the stack base. (PSD, Regulation 2, Rule 5)

37. The Owner/Operator of GGS shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Regulation 1-501)

38. Within 180 days of the issuance of the Authority to Construct for the GGS, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 26, 29, 30 and 32. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

39. Prior to the issuance of the BAAQMD Authority to Construct for the GGS, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and 101.7 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

40. Prior to the start of construction of the GGS, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and 101.7 tons of Particulate Matter less than 10 microns. (Offsets)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the GGS shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine or HRSG duct burner. (Regulation 2-6-404.1)

42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the federal Acid Rain Program, the owner/operator of the Gateway Generating Station shall submit an application for a Title IV operating permit S-44) in accordance with 40 C.F.R. Part 72. (Regulation 2, Rule 7)

43. The GGS shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

**Conditions for S-47 Emergency Fire Pump Engine**

44. The owner/operator shall not operate S-47 Fire Pump Diesel Engine more than 50 hours per year for reliability-related activities. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3)or (e)(2)(B)(3), offsets)

45. The owner/operator shall operate S-47 Fire Pump Diesel Engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or federal emission limits is not limited. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection 9e)(2)(A)(3) or (e)(2)(B)(3))

46. The owner/operator shall operate S-47 Fire Pump Diesel Engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1), cumulative increase)

47. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.

Hours of operation for reliability-related activities (maintenance and testing).
Hours of operation for emission testing to show compliance with emission limits.
Hours of operation (emergency).
For each emergency, the nature of the emergency condition.
Fuel usage for each engine(s).

(Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)

# VI Recommendation

The APCO has preliminarily concluded that the proposed Gateway Generating Station power plant, which is composed of the permitted sources listed below, complies with all applicable District, state and federal rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S-41 Combustion Turbine Generator (CTG) #1, General Electric Frame 7FA Model PG 7231 or equivalent, 1872 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst

S-42 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 395 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst

S-43 Combustion Turbine Generator (CTG) #2, General Electric Frame 7FA Model PG 7231 or equivalent, 1872 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst

S-44 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 395 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst

S-45 Natural Gas-fired Fuel Preheater (Exempt)

S-46 Dry Cooling System (Exempt)

S-47 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input

S-48 Oil-Water Separator, Highland Tank, HTC, 8000 gallon

This document is subject to the public notice, public comment, and public inspection requirements of District Regulations 2-2-405 through6 and 2-2-407 and 40 C.F.R. sections 124.10 and 124.11. Accordingly, a notice inviting written public comment will be published in a newspaper of general circulation in the area of the proposed Gateway Generating Station and mailed to certain entities. The public inspection and comment period will end 30 days after the date of such publication. Written comments on this document should be directed to:

Brian K. Lusher
Air Quality Engineer
**Bay Area Air Quality Management District**
939 Ellis Street
San Francisco CA 94109
blusher@baaqmd.gov

# Appendix A

## Emission Calculations

The following physical constants and standard conditions were utilized to derive the criteria-pollutant emission factors used to estimate and verify criteria pollutant and toxic air contaminant emissions submitted in the permit application. The criteria emission calculations were prepared by the applicant's consultant and are based on a combustion model. The District has verified these values using the calculations shown below. For the toxic air contaminants the District revised the calculation submitted by the applicant.

| | |
|---|---|
| standard temperature[a]: | 70°F |
| standard pressure[a]: | 14.7 psia |
| molar volume: | 386.8 dscf/lbmol |
| ambient oxygen concentration: | 20.95% |
| dry flue gas factor[b]: | 8743 dscf/MM Btu |
| natural gas higher heating value: | 1050 Btu/dscf |

[a] BAAQMD standard conditions per Regulation 1, Section 228.

[b] F-factor is based upon the assumption of complete stoichiometric combustion of natural gas. In effect, it is assumed that all excess air present before combustion is emitted in the exhaust gas stream. Value shown reflects the typical composition and heat content of utility-grade natural gas in San Francisco bay area.

Table A-1 summarizes the regulated air pollutant emission factors that were used to calculate mass emission rates for each source. All units are pounds per million Btu of natural gas fired based upon the high heating value (HHV). All emission factors are after abatement by applicable control equipment.

**Table A-1**
**Controlled Regulated Air Pollutant Emission Factors for Gas Turbines and HRSGs**

| Pollutant | Source | | | |
|---|---|---|---|---|
| | Gas Turbine | | Gas Turbine & HRSG Combined | |
| | lb/MM Btu | lb/hr | lb/MM Btu | lb/hr |
| Nitrogen Oxides (as $NO_2$) | 0.00725[a] | 13.57 | 0.00725[a] | 15.18 |
| Carbon Monoxide | 0.00882[b] | 16.51 | 0.00882[b] | 18.47 |
| Precursor Organic Compounds | 0.00254 | 4.75 | 0.00254 | 5.32 |
| Particulate Matter ($PM_{10}$) | 0.00588 | 11.00 | 0.00573 | 12.0 |
| Sulfur Dioxide | 0.0028 | 5.24 | 0.0028 | 5.86 |

[a] based upon stack concentration of 2.0 ppmvd $NO_x$ @ 15% $O_2$ that reflects the use of dry low-$NO_x$ combustors at the CTG, low-$NO_x$ burners at the HRSG, and abatement by the proposed Selective Catalytic Reduction Systems with ammonia injection.

[b] based upon the permit condition emission limit of 4 ppmvd CO @ 15% $O_2$.that reflects abatement by proposed Oxidation Catalysts.

REGULATED AIR POLLUTANTS

**NITROGEN OXIDE EMISSION FACTORS**

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined $NO_x$ emissions from the CTG and HRSG will be 2.0 ppmv, dry @ 15% $O_2$. This emission concentration will also apply when the HRSG duct burners are in operation. This concentration is converted to a mass emission factor as follows:

(2.0 ppmvd)(20.95 - 0)/(20.95 - 15) = 7.042 ppmv $NO_x$, dry @ 0% $O_2$

$(7.042/10^6)$(1 lbmol/386.8 dscf)(46.01 lb $NO_2$/lbmol)(8743 dscf/MM Btu)

**= 0.00732 lb $NO_2$/MM Btu**

**Calculations shown below are based on 0.00725 lb $NO_2$/MMBtu emission factor submitted by the applicant.**

The $NO_x$(as $NO_2$) mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.00725 lb/MM Btu)(1872 MM Btu/hr) = **13.57 lb $NO_x$(as $NO_2$)/hr**

The $NO_x$ mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:

(0.00725 lb/MM Btu)(395 MM Btu/hr) = **2.86 lb $NO_x$(as $NO_2$)/hr**

The $NO_x$ mass emission rate when the gas turbine and duct burner firing is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:

(0.00725 lb/MM Btu)(2094.4 MM Btu/hr) = **15.18 lb $NO_x$(as $NO_2$)/hr**

**CARBON MONOXIDE EMISSION FACTORS**

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined CO emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled CO emission limit of 4 ppmv, dry @ 15% $O_2$ during all operating modes except gas turbine start-up and shutdown. The emission factor corresponding to this emission concentration is calculated as follows:

(4 ppmv)(20.95 - 0)/(20.95 - 15) = 14.08 ppmv, dry @ 0% $O_2$

$(14.08/10^6)$(lbmol/386.8 dscf)(28 lb CO/lbmol)(8743 dscf/MM Btu)

= **0.0089 lb CO/MM Btu**

**Calculations shown below are based on 0.00882 lb CO/MMBtu emission factor which is consistent with the information submitted by the applicant (18.5 lb/hr maximum).**

The CO maximum mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.00882 lb/MM Btu)(1872 MM Btu/hr) = **16.51 lb CO/hr**

The CO mass maximum emission rate when duct burner firing occurs at the maximum firing rate of the HRSG and is calculated as follows:

(0.00882 lb/MM Btu)(395 MM Btu/hr) = **3.48 lb CO/hr**

The CO mass emission rate when gas turbine and duct burner firing occurs is based upon the maximum combined firing rate of the CTG and HRSG and is calculated as follows:

(0.00882 lb/MM Btu)(2094.4 MM Btu/hr) = **18.47 lb CO/hr**

**PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS**

Combustion Gas Turbine

The POC emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled emission limit of 2 ppmv, dry @ 15% $O_2$ during all operating modes except gas turbine start-up and shutdown. The POC emission factor corresponding to this emission concentration is calculated as follows:

(2 ppmv)(20.95 - 0)/(20.95 - 15) = 7.085 ppmv, dry @ 0% $O_2$

$(7.085/10^6)$(lbmol/386.8 dscf)(16 lb $CH_4$/lbmol)(8743 dscf/MM Btu)
= **0.00256 lb POC/MM Btu**

**Calculations shown below are based on 0.00254 lb POC/MMBtu emission factor which is consistent with the information submitted by the applicant (5.3 lb/hr maximum).**

The POC mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.00254 lb/MM Btu)(1872 MM Btu/hr) = **4.75 lb POC/hr**

HRSG

The POC mass emission rate when duct burner firing occurs is based upon the maximum firing rate of the HRSG and is calculated as follows:

(0.00254 lb/MM Btu)(395 MM Btu/hr) = **1.00 lb POC/hr**

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The POC mass emission rate when duct burner firing occurs is based upon the maximum firing rate of the Gas Turbine and HRSG combined and is calculated as follows:

(0.00254 lb/MM Btu)(2094.4 MM Btu/hr) = **5.3 lb POC/hr**

**PARTICULATE MATTER ($PM_{10}$) EMISSION FACTORS**

Combustion Gas Turbine and HRSG Combined

The applicant has determined a $PM_{10}$ emission factor of 0.0052 lb/MMBtu at maximum load for the gas turbine and HRSG. It is assumed that this $PM_{10}$ emission factor includes secondary $PM_{10}$ formation of particulate sulfates. The corresponding $PM_{10}$ emission rate is:
(0.00573 lb/MMBtu)/(2094.4 MM Btu/hr) = **12.0 lb/hr**

Grain Loading Calculation for Gas Turbine and HRSG

PM-10 Maximum Emission Rate 12 lb/hr
Firing Rate 2094.4 MMBtu/hr
F-factor 8655 dscf/MMBtu
lb = 7000 grains
Regulation 6 O2 Concentration 6%
Ambient Air O2 Concentration 20.9%

grains/dscf = (12 lb/hr x 7000 grains/lb)/(2094.4 MMBtu/hr x (8655 dscf/MMBtu x 20.9/(20.9 - 6))

grains/dscf = 0.0013

**HRSG**

The $PM_{10}$ emission factor is based upon the applicant's assumption of 1 lb/hr for the HRSG $PM_{10}$ emission rate. The corresponding $PM_{10}$ emission factor is therefore:
(1 lb $PM_{10}$/hr)/(395 MM Btu/hr) = **0.00253 lb $PM_{10}$/MM Btu**

**SULFUR DIOXIDE EMISSION FACTORS**

Combustion Gas Turbine & Heat Recovery Steam Generator

The $SO_2$ emission factor is based upon annual average natural gas sulfur content of 0.75 grains per 100 scf and a higher heating value of 1012 Btu/scf as specified by PG&E.

The sulfur emission factor is calculated as follows:
$SO_2$ lb/hr

Natural Gas 1 grains of S/100 scf for Maximum Hourly

$SO_2$ = (1 gr/100 scf)(lb/7000 gr)(1/1020 BTU/scf)(1 x 10E6 Btu/MMBtu)(64 lb $SO_2$/32 lb S) = 0.0028 lb/MMBtu

Natural Gas 0.75 grains of S/100 scf for Annual Average

$SO_2$ = (0.75 gr/100 scf)(lb/7000 gr)(1/1020 BTU/scf)(1 x 10E6 Btu/MMBtu)(64 lb $SO_2$/32 lb S) = 0.0021 lb/MMBtu

<u>Max Hourly $SO_2$</u>

The corresponding mass $SO_2$ emission rate at the maximum combined firing rate of 2094.4 MM Btu/hr is:
(0.0028 lb $SO_2$/MM Btu)(2094.4 MM Btu/hr) = 5.86 lb/hr

**Annual Average $SO_2$**

The corresponding $SO_2$ mass emission rate at the maximum gas turbine firing rate of 2094.4 MM Btu/hr is:
(0.0021 lb $SO_2$/MM Btu)(2094.4 MM Btu/hr) = 4.40 lb/hr

This maximum lb/MMBtu value is converted to an emission concentration as follows:
(0.0028 lb $SO_2$/MM Btu)(386.8 dscf/lb-mol)(lb-mol/64.06 lb $SO_2$)($10^6$ Btu/8743 dscf)
= 1.93 ppmvd $SO_2$ @ 0% $O_2$

which is equivalent to:
(1.93 ppmvd)(20.95 - 15)/20.95 = 0.55 ppmv $SO_2$, dry @ 15% $O_2$

Gateway Generating Station
Plant No. 18143
Application No. 17182
BAAQMD 051208

lb/hour values calculated by Sierrra Research using combustion modeling prepared for the Gateway Generating Station

| Unit | Mode | NOx lb/hr | CO lb/hr | POC lb/hr |
|---|---|---|---|---|
| Turbine 1 | Base | 13.40 | 16.31 | 4.67 |
| Turbine 2 | Base | 13.40 | 16.31 | 4.67 |
| Turbine 1 | Peak | 15.18 | 18.49 | 5.29 |
| Turbine 2 | Peak | 15.18 | 18.49 | 5.29 |
| Turbine 1 | Startup/Shutdown | 100.00 | 900.00 | 16.00 |
| Turbine 2 | Startup/Shutdown | 100.00 | 900.00 | 16.00 |
| Turbine 1 | Startup/Shutdown Max Hourly | 160.00 | | |
| Turbine 2 | Startup/Shutdown Max Hourly | 160.00 | | |

Case 1: Summer Peaking Operation (Maximum Daily NOx, CO and VOC emissions)

| Unit | Mode | Worst Case hrs/day | hrs/year | NOx lb/day | NOx tons/year | CO lb/day | CO tons/year | POC lb/day | POC tons/year |
|---|---|---|---|---|---|---|---|---|---|
| Turbine 1 | Base | 0 | 1130 | 0 | 7.57 | 0 | 9.22 | 0 | 2.64 |
| Turbine 2 | Base | 0 | 1130 | 0 | 7.57 | 0 | 9.22 | 0 | 2.64 |
| Turbine 1 | Peak | 18 | 4960 | 273.24 | 37.65 | 332.82 | 45.86 | 95.22 | 13.12 |
| Turbine 2 | Peak | 18 | 4960 | 273.24 | 37.65 | 332.82 | 45.86 | 95.22 | 13.12 |
| Turbine 1 | Startup/Shutdown | 6 | 330 | 600 | 16.50 | 5400 | 148.50 | 96.00 | 2.64 |
| Turbine 2 | Startup/Shutdown | 6 | 330 | 600 | 16.50 | 5400 | 148.50 | 96.00 | 2.64 |
| Total Turbines + Ductburner | | | | 1746.5 | 123.4 | 11465.6 | 407.1 | 382.4 | 36.8 |

Case 2: Year Round Operation, Weekly Startups (Maximum Annual CO Emissions)

| Unit | Mode | Worst Case hrs/day | hrs/year | NOx lb/day | NOx tons/year | CO lb/day | CO tons/year | POC lb/day | POC tons/year |
|---|---|---|---|---|---|---|---|---|---|
| Turbine 1 | Base | 6 | 324 | 80.4 | 2.17 | 97.86 | 2.64 | 28.02 | 0.76 |
| Turbine 2 | Base | 6 | 324 | 80.4 | 2.17 | 97.86 | 2.64 | 28.02 | 0.76 |
| Turbine 1 | Peak | 12 | 4380 | 182.16 | 33.24 | 221.88 | 40.49 | 63.48 | 11.59 |
| Turbine 2 | Peak | 12 | 4380 | 182.16 | 33.24 | 221.88 | 40.49 | 63.48 | 11.59 |
| Turbine 1 | Startup/Shutdown | 6 | 520 | 600.0 | 26.00 | 5400 | 234.00 | 96.00 | 4.16 |
| Turbine 2 | Startup/Shutdown | 6 | 520 | 600.0 | 26.00 | 5400 | 234.00 | 96.00 | 4.16 |
| Total Turbines + Ductburner | | | | 1725.1 | 122.8 | 11439.5 | 554.3 | 375.0 | 33.0 |

Case 3: Year Round Peaking Operation (Maximum Annual NOx and VOC Emissions)

| Unit | Mode | Worst Case hrs/day | hrs/year | NOx lb/day | NOx tons/year | CO lb/day | CO tons/year | POC lb/day | POC tons/year |
|---|---|---|---|---|---|---|---|---|---|
| Turbine 1 | Base | 7 | 1825 | 93.8 | 12.23 | 114.17 | 14.88 | 32.69 | 4.26 |
| Turbine 2 | Base | 7 | 1825 | 93.8 | 12.23 | 114.17 | 14.88 | 32.69 | 4.26 |
| Turbine 1 | Peak | 16 | 5840 | 242.88 | 44.33 | 295.84 | 53.99 | 84.64 | 15.45 |
| Turbine 2 | Peak | 16 | 5840 | 242.88 | 44.33 | 295.84 | 53.99 | 84.64 | 15.45 |
| Turbine 1 | Startup/Shutdown | 1 | 365 | 160.0 | 18.25 | 900 | 164.25 | 16.00 | 2.92 |
| Turbine 2 | Startup/Shutdown | 1 | 365 | 160.0 | 18.25 | 900 | 164.25 | 16.00 | 2.92 |
| Total Turbines + Ductburner | | | | 993.4 | 149.6 | 2620.0 | 466.2 | 266.7 | 45.3 |

Case 4: Year Round Operation, no startups

| Unit | Mode | Worst Case hrs/day | hrs/year | NOx lb/day | NOx tons/year | CO lb/day | CO tons/year | POC lb/day | POC tons/year |
|---|---|---|---|---|---|---|---|---|---|
| Turbine 1 | Base | 1.5 | 3660 | 20.1 | 24.52 | 24.465 | 29.85 | 7.005 | 8.55 |
| Turbine 2 | Base | 1.5 | 3660 | 20.1 | 24.52 | 24.465 | 29.85 | 7.005 | 8.55 |
| Turbine 1 | Peak | 22.5 | 5100 | 341.55 | 38.71 | 416.025 | 47.15 | 119.03 | 13.49 |
| Turbine 2 | Peak | 22.5 | 5100 | 341.55 | 38.71 | 416.025 | 47.15 | 119.03 | 13.49 |
| Turbine 1 | Startup/Shutdown | 0 | 0 | 0.0 | 0.00 | 0 | 0.00 | 0.00 | 0.00 |
| Turbine 2 | Startup/Shutdown | 0 | 0 | 0.0 | 0.00 | 0 | 0.00 | 0.00 | 0.00 |
| Total Turbines + Ductburner | | | | 723.3 | 126.5 | 881.0 | 154.0 | 252.1 | 44.1 |

| Toxic Air Contaminant | Project lb/hour | Project lb/year | Acute Risk Screening Trigger Level (lb/hr) | Chronic Risk Screening Trigger Level (lb/yr) |
|---|---|---|---|---|
| 1,3-Butadiene | 5.22E-04 | 4.35E+00 | None | 1.10E+00 |
| Acetaldehyde | 5.63E-01 | 4.69E+03 | None | 6.40E+01 |
| Acrolein | 7.76E-02 | 6.47E+02 | 4.20E-04 | 2.30E+00 |
| Ammonia | 5.86E+01 | 4.89E+05 | 7.10E+00 | 7.70E+03 |
| Benzene | 5.46E-02 | 4.55E+02 | 2.90E+00 | 6.40E+00 |
| Benzo(a)anthracene | 9.28E-05 | 7.73E-01 | None | None |
| Benzo(a)pyrene | 5.71E-05 | 4.76E-01 | None | 1.10E-02 |
| Benzo(b)fluoranthene | 4.64E-05 | 3.87E-01 | None | None |
| Benzo(k)fluoranthene | 4.52E-05 | 3.76E-01 | None | None |
| Chrysene | 1.03E-04 | 8.62E-01 | None | None |
| Dibenz(a,h)anthracene | 9.65E-05 | 8.04E-01 | None | None |
| Ethylbenzene | 7.35E-02 | 6.12E+02 | None | 7.70E+04 |
| Formaldehyde | 1.88E+00 | 1.57E+04 | 2.10E-01 | 3.00E+01 |
| Hexane | 1.06E+00 | 8.86E+03 | None | 2.70E+05 |
| Indeno(1,2,3-cd)pyrene | 9.65E-05 | 8.04E-01 | None | None |
| Naphthalene | 6.82E-03 | 5.68E+01 | None | None |
| Propylene | 3.17E+00 | 2.64E+04 | None | 1.20E+05 |
| Propylene Oxide | 1.96E-01 | 1.64E+03 | 6.80E+00 | 4.90E+01 |
| Toluene | 2.92E-01 | 2.43E+03 | 8.20E+01 | 1.20E+04 |
| Xylene (Total) | 1.07E-01 | 8.93E+02 | 4.90E+01 | 2.70E+04 |
| Sulfuric Acid Mist (H2SO4) | 9.00E-01 | 5.61E+03 | 2.60E-01 | 3.90E+01 |
| Diesel Particulate Matter | 7.40E-02 | 3.70E+00 | None | 5.80E-01 |
| Benzo(a)pyrene equivalents | 1.88E-04 | 1.56E+00 | None | 1.10E-02 |

Notes:
Diesel Particulate Matter is a surrogate for all air toxics emitted by the diesel engine and is used to evaluate health risk impacts from the fire pump engine.
Emissions from the dew point heater are not included since this source is exempt from District permit requirements.
PAH impacts are evaluated as Benzo(a)pyrene equivalents.

| | Equivalency Factor |
|---|---|
| Benzo(a)anthracene | 0.1 |
| Benzo(a)pyrene | 1 |
| Benzo(b)fluoranthrene | 0.1 |
| Benzo(k)fluoranthene | 0.1 |
| Chrysene | 0.01 |
| Dibenz(a,h)anthracene | 1.05 |
| Indeno(1,2,3-cd)pyrene | 0.1 |

| Toxic Air Contaminant | EF lb/MMBtu | Per Turbine Firing Rate MMBtu/hour | Per Turbine Firing Rate MMBtu/year | Per Turbine lb/hour | Per Turbine lb/year | Total CT lb/hour | Total CT lb/year |
|---|---|---|---|---|---|---|---|
| 1,3-Butadiene | 1.25E-07 | 2094.4 | 17450000 | 2.61E-04 | 2.17E+00 | 5.22E-04 | 4.35E+00 |
| Acetaldehyde | 1.34E-04 | | | 2.81E-01 | 2.34E+03 | 5.63E-01 | 4.69E+03 |
| Acrolein | 1.85E-05 | | | 3.88E-02 | 3.23E+02 | 7.76E-02 | 6.47E+02 |
| Ammonia | 1.40E-02 | | | 2.93E+01 | 2.44E+05 | 5.86E+01 | 4.89E+05 |
| Benzene | 1.30E-05 | | | 2.73E-02 | 2.28E+02 | 5.46E-02 | 4.55E+02 |
| Benzo(a)anthracene | 2.22E-08 | | | 4.64E-05 | 3.87E-01 | 9.28E-05 | 7.73E-01 |
| Benzo(a)pyrene | 1.36E-08 | | | 2.85E-05 | 2.38E-01 | 5.71E-05 | 4.76E-01 |
| Benzo(b)fluoranthene | 1.11E-08 | | | 2.32E-05 | 1.93E-01 | 4.64E-05 | 3.87E-01 |
| Benzo(k)fluoranthene | 1.08E-08 | | | 2.26E-05 | 1.88E-01 | 4.52E-05 | 3.76E-01 |
| Chrysene | 2.47E-08 | | | 5.17E-05 | 4.31E-01 | 1.03E-04 | 8.62E-01 |
| Dibenz(a,h)anthracene | 2.30E-08 | | | 4.83E-05 | 4.02E-01 | 9.65E-05 | 8.04E-01 |
| Ethylbenzene | 1.75E-05 | | | 3.68E-02 | 3.06E+02 | 7.35E-02 | 6.12E+02 |
| Formaldehyde | 4.50E-04 | | | 9.42E-01 | 7.85E+03 | 1.88E+00 | 1.57E+04 |
| Hexane | 2.54E-04 | | | 5.32E-01 | 4.43E+03 | 1.06E+00 | 8.86E+03 |
| Indeno(1,2,3-cd)pyrene | 2.30E-08 | | | 4.83E-05 | 4.02E-01 | 9.65E-05 | 8.04E-01 |
| Naphthalene | 1.63E-06 | | | 3.41E-03 | 2.84E+01 | 6.82E-03 | 5.68E+01 |
| Propylene | 7.56E-04 | | | 1.58E+00 | 1.32E+04 | 3.17E+00 | 2.64E+04 |
| Propylene Oxide | 4.69E-05 | | | 9.81E-02 | 8.18E+02 | 1.96E-01 | 1.64E+03 |
| Toluene | 6.96E-05 | | | 1.46E-01 | 1.21E+03 | 2.92E-01 | 2.43E+03 |
| Xylene (Total) | 2.56E-05 | | | 5.36E-02 | 4.47E+02 | 1.07E-01 | 8.93E+02 |
| Sulfuric Acid Mist (H2SO4) | | | | 4.50E-01 | 2.81E+03 | 9.00E-01 | 5.61E+03 |
| Benzo(a)pyrene equivalents | 4.48E-08 | | | 9.38E-05 | 7.81E-01 | 1.88E-04 | 1.56E+00 |

Formaldehyde emissions reflect 50% destruction due to oxidation catalyst.

| | Equivalency Factor |
|---|---|
| Benzo(a)anthracene | 0.1 |
| Benzo(a)pyrene | 1 |
| Benzo(b)fluoranthrene | 0.1 |
| Benzo(k)fluoranthene | 0.1 |
| Chrysene | 0.01 |
| Dibenz(a,h)anthracene | 1.05 |
| Indeno(1,2,3-cd)pyrene | 0.1 |

Ammonia lb/MMBtu = ppm x 1/molar volume x MW x Fd x 20.9/(20.9 - %O2)

ppm = 10 ppm @15%O2 limit
molar volume = 386.8 dscf/lbmol @ 14.696 psia, 70 deg. F
MW = molecular weight, lb/lb-mol
Fd = 8743 dscf/MMBtu for Natural Gas @ 70 deg. F

Ammonia lb/MMBtu = 10 E-06 ft3 of NH3/ft3 stack gas x 1/386.8 dscf/lb-mol x 17 lb/lb-mol x 8743 dscf/MMBtu x 20.9/(20.9 - 15)
Ammonia lb/MMBtu = 0.014

| Toxic Air Contaminant | EF lb/MMBtu | Per Turbine Firing Rate MMBtu/hr | Per Turbine Firing Rate MMBtu/yr | Per Turbine lb/hour | Per Turbine lb/year | Total CT lb/hour | Total CT lb/year |
|---|---|---|---|---|---|---|---|
| 1,3-Butadiene | 1.25E-07 | 2094.4 | 17450000 | 2.61E-04 | 2.17E+00 | 5.22E-04 | 4.35E+00 |
| Acetaldehyde | 1.34E-04 | | | 2.81E-01 | 2.34E+03 | 5.63E-01 | 4.69E+03 |
| Acrolein | 1.85E-05 | | | 3.88E-02 | 3.23E+02 | 7.76E-02 | 6.47E+02 |
| Ammonia | 1.40E-02 | | | 2.93E+01 | 2.44E+05 | 5.86E+01 | 4.89E+05 |
| Benzene | 1.30E-05 | | | 2.73E-02 | 2.28E+02 | 5.46E-02 | 4.55E+02 |
| Benzo(a)anthracene | 2.22E-08 | | | 4.64E-05 | 3.87E-01 | 9.28E-05 | 7.73E-01 |
| Benzo(a)pyrene | 1.36E-08 | | | 2.85E-05 | 2.38E-01 | 5.71E-05 | 4.76E-01 |
| Benzo(b)fluoranthene | 1.11E-08 | | | 2.32E-05 | 1.93E-01 | 4.64E-05 | 3.87E-01 |
| Benzo(k)fluoranthene | 1.08E-08 | | | 2.26E-05 | 1.88E-01 | 4.52E-05 | 3.76E-01 |
| Chrysene | 2.47E-08 | | | 5.17E-05 | 4.31E-01 | 1.03E-04 | 8.62E-01 |
| Dibenz(a,h)anthracene | 2.30E-08 | | | 4.83E-05 | 4.02E-01 | 9.65E-05 | 8.04E-01 |
| Ethylbenzene | 1.75E-05 | | | 3.68E-02 | 3.06E+02 | 7.35E-02 | 6.12E+02 |
| Formaldehyde | 4.50E-04 | | | 9.42E-01 | 7.85E+03 | 1.88E+00 | 1.57E+04 |
| Hexane | 2.54E-04 | | | 5.32E-01 | 4.43E+03 | 1.06E+00 | 8.86E+03 |
| Indeno(1,2,3-cd)pyrene | 2.30E-08 | | | 4.83E-05 | 4.02E-01 | 9.65E-05 | 8.04E-01 |
| Naphthalene | 1.63E-06 | | | 3.41E-03 | 2.84E+01 | 6.82E-03 | 5.68E+01 |
| Propylene | 7.56E-04 | | | 1.58E+00 | 1.32E+04 | 3.17E+00 | 2.64E+04 |
| Propylene Oxide | 4.69E-05 | | | 9.81E-02 | 8.18E+02 | 1.96E-01 | 1.64E+03 |
| Toluene | 6.96E-05 | | | 1.46E-01 | 1.21E+03 | 2.92E-01 | 2.43E+03 |
| Xylene (Total) | 2.56E-05 | | | 5.36E-02 | 4.47E+02 | 1.07E-01 | 8.93E+02 |
| Sulfuric Acid Mist (H2SO4) | | | | 4.50E-01 | 2.81E+03 | 9.00E-01 | 5.61E+03 |
| Benzo(a)pyrene equiv. | 4.48E-08 | | | 9.38E-05 | 7.81E-01 | 1.88E-04 | 1.56E+00 |

Formaldehyde emissions reflect 50% destruction due to oxidation catalyst.

| | Equivalency Factor |
|---|---|
| Benzo(a)anthracene | 0.1 |
| Benzo(a)pyrene | 1 |
| Benzo(b)fluoranthrene | 0.1 |
| Benzo(k)fluoranthene | 0.1 |
| Chrysene | 0.01 |
| Dibenz(a,h)anthracene | 1.05 |
| Indeno(1,2,3-cd)pyrene | 0.1 |

Ammonia lb/MMBtu = ppm x 1/molar volume x MW x Fd x 20.9/(20.9 - %O2)

ppm = 10 ppm @15%O2 limit
molar volume = 386.8 dscf/lbmol @ 14.696 psia, 70 deg. F
MW = molecular weight, lb/lb-mol
Fd = 8743 dscf/MMBtu for Natural Gas @ 70 deg. F

Ammonia lb/MMBtu = 10 E-06 ft3 of NH3/ft3 stack gas x 1/386.8 dscf/lb-mol x 17 lb/lb-mol x 8743 dscf/MMBtu x 20.9/(20.9 - 15)
Ammonia lb/MMBtu = 0.014

CATEF Gas Turbine TAC Emission Factors

| ID | System Type | Material Type | SCC | APC Device | Other Description | CAS | Substance | Max Emission factor | Mean | Median | Unit | lb/MMBtu |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4543 | Turbine | Natural gas | 20200203 | COC/SCR | None | 106-99-0 | 1,3-Butadiene | 1.33E-04 | 1.27E-04 | 1.24E-04 | lbs/MMcf | 1.25E-07 |
| 4568 | Turbine | Natural gas | 20200203 | COC/SCR | None | 75-07-0 | Acetaldehyde | 5.11E-01 | 1.37E-01 | 5.38E-02 | lbs/MMcf | 1.34E-04 |
| 4573 | Turbine | Natural gas | 20200203 | COC/SCR | None | 107-02-8 | Acrolein | 6.93E-02 | 1.89E-02 | 1.09E-02 | lbs/MMcf | 1.85E-05 |
| 4584 | Turbine | Natural gas | 20200203 | COC/SCR | None | 71-43-2 | Benzene | 4.72E-02 | 1.33E-02 | 1.01E-02 | lbs/MMcf | 1.30E-05 |
| 4593 | Turbine | Natural gas | 20200203 | COC/SCR | None | 56-55-6 | Benzo(a)anthracene | 1.34E-04 | 2.26E-05 | 3.61E-06 | lbs/MMcf | 2.22E-08 |
| 4598 | Turbine | Natural gas | 20200203 | COC/SCR | None | 50-32-8 | Benzo(a)pyrene | 9.16E-05 | 1.39E-05 | 2.57E-06 | lbs/MMcf | 1.36E-08 |
| 4603 | Turbine | Natural gas | 20200203 | COC/SCR | None | 205-99-2 | Benzo(b)fluoranthene | 6.72E-05 | 1.13E-05 | 2.87E-06 | lbs/MMcf | 1.11E-08 |
| 4618 | Turbine | Natural gas | 20200203 | COC/SCR | None | 207-08-9 | Benzo(k)fluoranthene | 6.72E-05 | 1.10E-05 | 2.87E-06 | lbs/MMcf | 1.08E-08 |
| 4623 | Turbine | Natural gas | 20200203 | COC/SCR | None | 218-01-9 | Chrysene | 1.50E-04 | 2.52E-05 | 4.99E-06 | lbs/MMcf | 2.47E-08 |
| 4628 | Turbine | Natural gas | 20200203 | COC/SCR | None | 53-70-3 | Dibenz(a,h)anthracene | 1.34E-04 | 2.35E-05 | 3.03E-06 | lbs/MMcf | 2.30E-08 |
| 4633 | Turbine | Natural gas | 20200203 | COC/SCR | None | 100-41-4 | Ethylbenzene | 5.70E-02 | 1.79E-02 | 9.74E-03 | lbs/MMcf | 1.75E-05 |
| 4648 | Turbine | Natural gas | 20200203 | COC/SCR | None | 50-00-0 | Formaldehyde | 6.87E+00 | 9.17E-01 | 1.12E-01 | lbs/MMcf | 8.99E-04 |
| 4653 | Turbine | Natural gas | 20200203 | COC/SCR | None | 110-54-3 | Hexane | 3.82E-01 | 2.59E-01 | 2.19E-01 | lbs/MMcf | 2.54E-04 |
| 4658 | Turbine | Natural gas | 20200203 | COC/SCR | None | 193-39-5 | Indeno(1,2,3-cd)pyrene | 1.34E-04 | 2.35E-05 | 2.87E-06 | lbs/MMcf | 2.30E-08 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4663 | Turbine | Natural gas | 20200203 | COC/SCR | None | 91-20-3 | Naphthalene | 7.88E-03 | 1.66E-03 | 9.26E-04 | lbs/MMcf | 1.63E-06 |
| 4678 | Turbine | Natural gas | 20200203 | COC/SCR | None | 115-07-1 | Propylene | 2.00E+00 | 7.71E-01 | 5.71E-01 | lbs/MMcf | 7.56E-04 |
| 4683 | Turbine | Natural gas | 20200203 | COC/SCR | None | 75-56-9 | Propylene Oxide | 5.87E-02 | 4.78E-02 | 4.48E-02 | lbs/MMcf | 4.69E-05 |
| 4693 | Turbine | Natural gas | 20200203 | COC/SCR | None | 108-88-3 | Toluene | 1.68E-01 | 7.10E-02 | 5.91E-02 | lbs/MMcf | 6.96E-05 |
| 4708 | Turbine | Natural gas | 20200203 | COC/SCR | None | 1330-20-7 | Xylene (Total) | 6.26E-02 | 2.61E-02 | 1.93E-02 | lbs/MMcf | 2.56E-05 |

Natural Gas 1020 Btu/scf

Appendix B

# PSD Modeling Results

# OFFICE MEMORANDUM

*May 29, 2008*

**TO:** Brian Lusher

**VIA:** Glen Long GEL
Scott Lutz SL
Brian Bateman
Barry Young
Doug Hall

**FROM:** Irma Salinas IS

**SUBJECT:** Pacific Gas & Electric Company; Gateway Generating Station Project, Plant #18143 (Antioch, Ca)
PSD Modeling Analysis (Permit Application # 17182)

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I have reviewed the modeling analysis report prepared by Sierra Research and submitted by Pacific Gas & Electric for the Gateway Generating Station Project. The attached document summarizes my findings.

Based upon the emission estimates provided in the December 2007 submittal, the proposed project would meet national ambient air quality standards for CO; and California ambient air quality standards (CAAQS) for CO. The proposed project does not cause a new exceedance of the standards and the California Clean Air Act does not require a plan to attain the state CAAQ $PM_{10}$ standards.

The air quality impact analysis was based on EPA approved models and calculation procedures, and was performed in accordance with Section 414 of the District's NSR Rule (Regulation 2, Rule 2).

# SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR

## Gateway Generating Station

*May 29, 2008*

**BACKGROUND**

Pacific Gas & Electric has submitted a permit application (# 17182) for a proposed 530 MW combined cycle power plant, the Gateway Generating Station (GGS). The facility is to consist of two natural gas-fired turbines with supplemental fired heat recovery steam generators, a dew point heater, and a diesel fire pump engine. The proposed project will result in an increase in air pollutant emission of CO triggering regulatory requirements for an air quality impact analysis.

**AIR QUALITY IMPACT ANALYSIS REQUIREMENTS**

Requirements for air quality impact analysis are given in the District's New Source Review (NSR) Rule: Regulation 2, Rule 2.

The criteria pollutant annual worst case emission increases for the Project are listed in Table I, along with the corresponding significant emission rates for air quality impact analysis.

**TABLE I**
**Comparison of proposed project's annual worst case emissions to significant emission rates for air quality impact analysis**

| Pollutant | Proposed Project's Emissions (tons/year) | Proposed Project's Emissions after offsets (tons/year) | Significant Emission Rate (tons/year) (Reg-2-2-304 to 2-2-306) | EPA PSD Significant Emission Rates for major stationary sources (tons/year) |
|---|---|---|---|---|
| $NO_x$ | 174.3 | 0 | 100 | 40 |
| CO | 555.1 | 555.1 | 100 | 100 |
| $PM_{10}$ | 101.7 | -10.5 | 100 | 15 |
| $SO_2$ | 37.0 | 37.0 | 100 | 40 |

Table I indicates that the proposed project emissions exceed District significant emission levels for carbon monoxide (CO). The source is classified as a major stationary source as defined under the Federal Clean Air Act. Therefore, the air quality impact must be investigated for all pollutants emitted in quantities larger than the EPA PSD significant emission rates (shown in the last column in Table I). Table I shows that the CO ambient impacts from the project must be modeled. The detailed requirements for an air quality impact analysis for these pollutants are given in Sections 304, 305 and 306 of the District's NSR Rule and 40 CFR 51.166 of the Code of Federal Regulations.

The District's NSR Rule also contains requirements for certain additional impact analyses associated with air pollutant emissions. An applicant for a permit that requires an air quality impact analysis must also, according to Section 417 of the NSR Rule, provide an analysis of the impact of the source and source-related growth on visibility, soils and vegetation.

## AIR QUALITY IMPACT ANALYSIS SUMMARY

The required contents of an air quality impact analysis are specified in Section 414 of Regulation 2 Rule 2. According to subsection 414.1, if the maximum air quality impacts of a new or modified stationary source do not exceed significance levels for air quality impacts, as defined in Section 2-2-233, no further analysis is required. (Consistent with EPA regulations, it is assumed that emission increases will not interfere with the attainment or maintenance of AAQS, or cause an exceedance of a PSD increment if the resulting maximum air quality impacts are less than specified significance levels). If the maximum impact for a particular pollutant is predicted to exceed the significance impact level, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis. EPA also requires a Class I increment analysis of any PSD source which increases $NO_2$ or $PM_{10}$ concentrations by 1 $\mu g/m^3$ or more (24-hour average) in a Class I area.

### Air Quality Modeling Methodology

Maximum ambient concentrations of CO were estimated for various plume dispersion scenarios using established modeling procedures. The plume dispersion scenarios addressed include simple terrain impacts (for receptors located below stack height), complex terrain impacts (for receptors located at or above stack height) and impacts due to building downwash.

Emissions from the turbines and burners will be exhausted from two 195 foot exhaust stacks, a dew point heater with a release height of 15 feet and the fire pump will be exhausted from a 10 feet 8 inches exhaust stack. Table II contains the emission rates used in each of the modeling scenarios: turbine commissioning, turbine startup, maximum 1-hour and maximum 8-hour. Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. Startup conditions were modeled with one turbine in startup mode, while the other turbine was in normal operation.

The EPA models SCREEN3 (version 96043) and AERMOD were used in the air quality impacts analysis. A land use analysis showed that the rural dispersion coefficients were required for the analysis. The models were run using three years of meteorological data (2004 through 2006) collected less than ½ mile northwest from the project site at the BAAQMD's Contra Costa Power Plant meteorological monitoring station. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Because complex terrain was located nearby, complex terrain impacts were considered.

**TABLE II**
**Averaging period emission rates used in modeling analysis (g/s)**

| Pollutant Source | Max. (1-hour) | Commis-sioning[1] (1-hour) | Start-up[2] (1-hour) | Start-up[2] (8-hour) | Max. (8-hour) |
|---|---|---|---|---|---|
| CO | | | | | |
| Turbine/Duct Burner 1 | 2.33 | 252.0 | 113.4 | 85.6 | 2.33 |
| Turbine/Duct Burner 2 | 2.33 | 252.0 | 2.33 | 85.6 | 2.33 |
| Fire Pump | 2.67E-2 | — | — | 3.33E-3 | 3.33E-3 |
| Dew point Heater | 2.41E-2 | — | 2.41E-2 | 2.41E-2 | 2.41E-2 |

[1]Commissioning is the original startup of a turbine and only occurs during the initial operation of the equipment after installation.

[2]Start-up is the beginning of any of the subsequent duty cycles to bring one turbine from idle status up to power production. Both turbines will not be in startup mode at the same time.

```
 *** AERMOD - VERSION 07026 ***     *** Gateway HRA impacts  P# 18143  A# 17182
***         05/19/08
                                    ***
***         14:48:43
```

*** SOURCE IDs DEFINING SOURCE GROUPS ***

| GROUP ID | SOURCE IDs |
|---|---|
| CNCR_RES | TURBINA1, TURBINB1, FRPUMP1 , |
| CNCR_WRK | TURBINA3, TURBINB3, FRPUMP3 , |
| CHI_RES | TURBINA2, TURBINB2, FRPUMP2 , |
| CHI_WRK | TURBINA4, TURBINB4, FRPUMP4 , |
| AHI | TURBINA5, TURBINB5, |

*** DIRECTION SPECIFIC BUILDING DIMENSIONS ***

SOURCE ID: TURBINA1
SOURCE ID: TURBINA2
SOURCE ID: TURBINA3
SOURCE ID: TURBINA4
SOURCE ID: TURBINA5

| IFV | BH | BW | BL | XADJ | YADJ | IFV | BH | BW | BL | XADJ | YADJ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 28.0, | 25.4, | 14.0, | -4.4, | -11.7, | 2 | 28.0, | 26.0, | 17.6, | -4.2, | -11.1, |
| 3 | 28.0, | 25.8, | 20.7, | -3.9, | -10.1, | 4 | 28.0, | 24.8, | 23.1, | -3.5, | -8.9, |
| 5 | 28.0, | 23.1, | 24.8, | -2.9, | -7.3, | 6 | 28.0, | 20.7, | 25.8, | -2.2, | -5.6, |
| 7 | 28.0, | 17.6, | 26.0, | -1.5, | -3.6, | 8 | 28.0, | 14.0, | 25.4, | -0.8, | -1.6, |
| 9 | 28.0, | 10.0, | 24.0, | 0.0, | 0.5, | 10 | 28.0, | 14.0, | 25.4, | -1.0, | 2.6, |
| 11 | 28.0, | 17.6, | 26.0, | -1.9, | 4.6, | 12 | 28.0, | 20.7, | 25.8, | -2.8, | 6.4, |
| 13 | 28.0, | 23.1, | 24.8, | -3.5, | 8.1, | 14 | 44.7, | 94.5, | 87.2, | -220.0, | 52.7, |
| 15 | 44.7, | 98.9, | 77.3, | -221.5, | 21.3, | 16 | 44.7, | 100.3, | 65.0, | -216.3, | -10.8, |
| 17 | 44.7, | 98.7, | 50.8, | -204.5, | -42.5, | 18 | 28.0, | 24.0, | 10.0, | -5.5, | 12.0, |
| 19 | 28.0, | 25.4, | 14.0, | -9.6, | 11.7, | 20 | 28.0, | 26.0, | 17.6, | -13.4, | 11.1, |
| 21 | 28.0, | 25.8, | 20.7, | -16.8, | 10.1, | 22 | 28.0, | 24.8, | 23.1, | -19.6, | 8.9, |
| 23 | 28.0, | 23.1, | 24.8, | -21.9, | 7.3, | 24 | 28.0, | 20.7, | 25.8, | -23.5, | 5.6, |
| 25 | 28.0, | 17.6, | 26.0, | -24.4, | 3.6, | 26 | 28.0, | 14.0, | 25.4, | -24.6, | 1.6, |
| 27 | 28.0, | 10.0, | 24.0, | -24.0, | -0.5, | 28 | 28.0, | 14.0, | 25.4, | -24.4, | -2.6, |
| 29 | 28.0, | 17.6, | 26.0, | -24.1, | -4.6, | 30 | 28.0, | 20.7, | 25.8, | -23.0, | -6.4, |
| 31 | 39.0, | 114.7, | 113.5, | -239.9, | 61.1, | 32 | 39.0, | 113.5, | 114.7, | -248.3, | 28.4, |
| 33 | 39.0, | 108.8, | 112.5, | -249.2, | -5.2, | 34 | 39.0, | 100.8, | 106.8, | -242.5, | -38.7, |
| 35 | 28.0, | 25.4, | 14.0, | -8.6, | -11.9, | 36 | 28.0, | 24.0, | 10.0, | -4.5, | -12.0, |

*** AERMOD - VERSION 07026 *** *** Gateway HRA impacts P# 18143 A# 17182
*** 05/19/08 ***
*** 14:48:43

*** DIRECTION SPECIFIC BUILDING DIMENSIONS ***

SOURCE ID: TURBINB1
SOURCE ID: TURBINB2
SOURCE ID: TURBINB3
SOURCE ID: TURBINB4
SOURCE ID: TURBINB5

| IFV | BH | BW | BL | XADJ | YADJ | IFV | BH | BW | BL | XADJ | YADJ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 28.0, | 25.4, | 14.0, | 36.0, | -4.6, | 2 | 28.0, | 26.0, | 17.6, | 34.3, | 2.9, |
| 3 | 28.0, | 25.8, | 20.7, | 31.6, | 10.4, | 4 | 28.0, | 24.8, | 23.1, | 28.0, | 17.5, |
| 5 | 28.0, | 23.1, | 24.8, | -2.9, | -7.3, | 6 | 28.0, | 20.7, | 25.8, | -2.2, | -5.6, |
| 7 | 28.0, | 17.6, | 26.0, | -1.5, | -3.6, | 8 | 28.0, | 14.0, | 25.4, | -0.8, | -1.6, |
| 9 | 28.0, | 10.0, | 24.0, | 0.0, | 0.5, | 10 | 28.0, | 14.0, | 25.4, | -1.0, | 2.6, |
| 11 | 28.0, | 17.6, | 26.0, | -1.9, | 4.6, | 12 | 28.0, | 20.7, | 25.8, | -2.8, | 6.4, |
| 13 | 28.0, | 23.1, | 24.8, | -3.5, | 8.1, | 14 | 28.0, | 24.8, | 23.1, | -4.2, | 9.5, |
| 15 | 44.7, | 98.9, | 77.3, | -257.0, | 41.8, | 16 | 44.7, | 100.3, | 65.0, | -254.8, | 3.2, |
| 17 | 44.7, | 98.7, | 50.8, | -244.9, | -35.4, | 18 | 28.0, | 24.0, | 10.0, | -46.5, | 12.0, |
| 19 | 28.0, | 25.4, | 14.0, | -50.0, | 4.6, | 20 | 28.0, | 26.0, | 17.6, | -51.9, | -2.9, |
| 21 | 28.0, | 25.8, | 20.7, | -52.3, | -10.4, | 22 | 28.0, | 24.8, | 23.1, | -51.0, | -17.5, |
| 23 | 28.0, | 23.1, | 24.8, | -21.9, | 7.3, | 24 | 28.0, | 20.7, | 25.8, | -23.5, | 5.6, |
| 25 | 28.0, | 17.6, | 26.0, | -24.4, | 3.6, | 26 | 28.0, | 14.0, | 25.4, | -24.6, | 1.6, |
| 27 | 28.0, | 10.0, | 24.0, | -24.0, | -0.5, | 28 | 28.0, | 14.0, | 25.4, | -24.4, | -2.6, |
| 29 | 28.0, | 17.6, | 26.0, | -24.1, | -4.6, | 30 | 39.0, | 112.5, | 108.8, | -203.6, | 56.5, |
| 31 | 39.0, | 114.7, | 113.5, | -213.5, | 29.7, | 32 | 39.0, | 113.5, | 114.7, | -216.9, | 2.0, |
| 33 | 39.0, | 108.8, | 112.5, | -213.7, | -25.7, | 34 | 39.0, | 100.8, | 106.8, | -204.0, | -52.7, |
| 35 | 28.0, | 25.4, | 14.0, | 31.8, | -19.0, | 36 | 28.0, | 24.0, | 10.0, | 36.5, | -12.0, |

SOURCE ID: FRPUMP1
SOURCE ID: FRPUMP2
SOURCE ID: FRPUMP3
SOURCE ID: FRPUMP4

| IFV | BH | BW | BL | XADJ | YADJ | IFV | BH | BW | BL | XADJ | YADJ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 39.0, | 89.8, | 97.9, | 21.9, | -15.9, | 2 | 39.0, | 100.8, | 106.8, | 19.1, | -3.4, |
| 3 | 39.0, | 108.8, | 112.5, | 15.8, | 9.2, | 4 | 39.0, | 113.5, | 114.7, | 12.0, | 21.6, |
| 5 | 39.0, | 114.7, | 113.5, | 7.8, | 33.3, | 6 | 39.0, | 112.5, | 108.8, | 3.3, | 44.0, |
| 7 | 39.0, | 106.8, | 100.8, | -1.2, | 53.4, | 8 | 39.0, | 97.9, | 89.8, | -5.7, | 61.1, |
| 9 | 5.2, | 15.0, | 15.0, | -24.0, | -5.5, | 10 | 5.2, | 14.8, | 14.8, | -22.6, | -8.2, |
| 11 | 39.0, | 106.8, | 100.8, | -47.0, | 72.5, | 12 | 39.0, | 112.5, | 108.8, | -63.7, | 72.0, |
| 13 | 39.0, | 114.7, | 113.5, | -78.4, | 69.3, | 14 | 39.0, | 113.5, | 114.7, | -90.7, | 64.5, |
| 15 | 39.0, | 108.8, | 112.5, | -100.3, | 57.8, | 16 | 39.0, | 100.8, | 106.8, | -106.8, | 49.2, |
| 17 | 39.0, | 89.8, | 97.9, | -110.1, | 39.2, | 18 | 39.0, | 76.0, | 86.0, | -110.0, | 28.0, |
| 19 | 39.0, | 89.8, | 97.9, | -119.8, | 15.9, | 20 | 39.0, | 100.8, | 106.8, | -125.9, | 3.4, |
| 21 | 39.0, | 108.8, | 112.5, | -128.3, | -9.2, | 22 | 39.0, | 113.5, | 114.7, | -126.7, | -21.6, |
| 23 | 39.0, | 114.7, | 113.5, | -121.3, | -33.3, | 24 | 39.0, | 112.5, | 108.8, | -112.2, | -44.0, |
| 25 | 39.0, | 106.8, | 100.8, | -99.6, | -53.4, | 26 | 39.0, | 97.9, | 89.8, | -84.1, | -61.1, |
| 27 | 6.4, | 9.0, | 9.0, | -29.0, | -3.5, | 28 | 5.2, | 14.8, | 14.8, | 7.8, | 8.2, |
| 29 | 39.0, | 106.8, | 100.8, | -53.8, | -72.5, | 30 | 39.0, | 112.5, | 108.8, | -45.2, | -72.0, |
| 31 | 39.0, | 114.7, | 113.5, | -35.1, | -69.3, | 32 | 39.0, | 113.5, | 114.7, | -24.0, | -64.5, |
| 33 | 39.0, | 108.8, | 112.5, | -12.2, | -57.8, | 34 | 39.0, | 100.8, | 106.8, | 0.0, | -49.2, |
| 35 | 39.0, | 89.8, | 97.9, | 12.2, | -39.2, | 36 | 39.0, | 76.0, | 86.0, | 24.0, | -28.0, |

*** AERMOD - VERSION 07026 *** *** Gateway HRA impacts P# 18143 A# 17182
*** 05/19/08 ***
*** 14:48:43

*** THE PERIOD ( 8760 HRS) AVERAGE CONCENTRATION VALUES FOR
SOURCE GROUP: CNCR_RES ***
INCLUDING SOURCE(S): TURBINA1, TURBINB1, FRPUMP1 ,
*** DISCRETE CARTESIAN RECEPTOR POINTS ***
** CONC OF OTHER IN MICROGRAMS/M**3
**

| X-COORD (M) | Y-COORD (M) | CONC | X-COORD (M) | Y-COORD (M) | CONC |
|---|---|---|---|---|---|
| 609150.00 | 4207550.00 | 0.07423 | 609175.00 | 4207550.00 | 0.08010 |
| 609200.00 | 4207550.00 | 0.08656 | 609225.00 | 4207550.00 | 0.09283 |
| 609250.00 | 4207550.00 | 0.09902 | 609275.00 | 4207550.00 | 0.10478 |
| 609300.00 | 4207550.00 | 0.11071 | 609325.00 | 4207550.00 | 0.11717 |
| 609350.00 | 4207550.00 | 0.12402 | 609375.00 | 4207550.00 | 0.13125 |
| 609400.00 | 4207550.00 | 0.13937 | 609425.00 | 4207550.00 | 0.14841 |
| 609450.00 | 4207550.00 | 0.15869 | 609475.00 | 4207550.00 | 0.16921 |
| 609500.00 | 4207550.00 | 0.18094 | 609525.00 | 4207550.00 | 0.19387 |
| 609550.00 | 4207550.00 | 0.20667 | 609575.00 | 4207550.00 | 0.21932 |
| 609600.00 | 4207550.00 | 0.23406 | 609625.00 | 4207550.00 | 0.25067 |
| 609650.00 | 4207550.00 | 0.26840 | 609675.00 | 4207550.00 | 0.28939 |
| 609700.00 | 4207550.00 | 0.30601 | 609725.00 | 4207550.00 | 0.32200 |
| 609750.00 | 4207550.00 | 0.33910 | 609775.00 | 4207550.00 | 0.35359 |
| 609800.00 | 4207550.00 | 0.36697 | 609825.00 | 4207550.00 | 0.37777 |
| 609850.00 | 4207550.00 | 0.38791 | 609875.00 | 4207550.00 | 0.39622 |
| 609900.00 | 4207550.00 | 0.40226 | 609925.00 | 4207550.00 | 0.40542 |
| 609950.00 | 4207550.00 | 0.40756 | 609975.00 | 4207550.00 | 0.40813 |
| 610000.00 | 4207550.00 | 0.40596 | 610025.00 | 4207550.00 | 0.40378 |
| 610050.00 | 4207550.00 | 0.39876 | 610075.00 | 4207550.00 | 0.39340 |
| 610100.00 | 4207550.00 | 0.38649 | 610125.00 | 4207550.00 | 0.38029 |
| 610150.00 | 4207550.00 | 0.37182 | 610175.00 | 4207550.00 | 0.36356 |
| 610200.00 | 4207550.00 | 0.35494 | 610225.00 | 4207550.00 | 0.34608 |
| 610250.00 | 4207550.00 | 0.33705 | 610275.00 | 4207550.00 | 0.32711 |
| 610300.00 | 4207550.00 | 0.31856 | 610325.00 | 4207550.00 | 0.30862 |
| 610350.00 | 4207550.00 | 0.30034 | 610375.00 | 4207550.00 | 0.29086 |
| 610400.00 | 4207550.00 | 0.28235 | 610425.00 | 4207550.00 | 0.27382 |
| 610450.00 | 4207550.00 | 0.26594 | 610475.00 | 4207550.00 | 0.25774 |
| 610500.00 | 4207550.00 | 0.25064 | 610525.00 | 4207550.00 | 0.24362 |
| 610550.00 | 4207550.00 | 0.23685 | 610575.00 | 4207550.00 | 0.23010 |
| 610600.00 | 4207550.00 | 0.22349 | 610625.00 | 4207550.00 | 0.21714 |
| 610650.00 | 4207550.00 | 0.21102 | 608300.00 | 4207575.00 | 0.04037 |
| 608325.00 | 4207575.00 | 0.04049 | 608350.00 | 4207575.00 | 0.04068 |

residential cancer risk

| | | | | |
|---|---|---|---|---|
| 608375.00 | 4207575.00 | 0.04094 | 608400.00 | 4207575.00 |
| 0.04116 | | | | |
| 608425.00 | 4207575.00 | 0.04131 | 608450.00 | 4207575.00 |
| 0.04144 | | | | |
| 608475.00 | 4207575.00 | 0.04148 | 608500.00 | 4207575.00 |
| 0.04155 | | | | |
| 608525.00 | 4207575.00 | 0.04152 | 608550.00 | 4207575.00 |
| 0.04148 | | | | |
| 608575.00 | 4207575.00 | 0.04150 | 608600.00 | 4207575.00 |
| 0.04136 | | | | |
| 608625.00 | 4207575.00 | 0.04109 | 608650.00 | 4207575.00 |
| 0.04086 | | | | |
| 608675.00 | 4207575.00 | 0.04065 | 608700.00 | 4207575.00 |
| 0.04038 | | | | |
| 608725.00 | 4207575.00 | 0.04028 | 608750.00 | 4207575.00 |
| 0.04022 | | | | |

*** AERMOD - VERSION 07026 *** *** Gateway HRA impacts P# 18143 A# 17182
*** 05/19/08 ***
*** 14:48:43

*** THE PERIOD ( 8760 HRS) AVERAGE CONCENTRATION VALUES FOR
SOURCE GROUP: CNCR_WRK ***
INCLUDING SOURCE(S): TURBINA3, TURBINB3, FRPUMP3 ,
*** DISCRETE CARTESIAN RECEPTOR POINTS ***
** CONC OF OTHER IN MICROGRAMS/M**3
**

| X-COORD (M) | Y-COORD (M) | CONC | X-COORD (M) | Y-COORD (M) | CONC |
|---|---|---|---|---|---|
| 608100.00 | 4207700.00 | 0.01422 | 608200.00 | 4207700.00 | 0.01515 |
| 608300.00 | 4207700.00 | 0.01655 | 608400.00 | 4207700.00 | 0.01829 |
| 608500.00 | 4207700.00 | 0.02031 | 608600.00 | 4207700.00 | 0.02263 |
| 608700.00 | 4207700.00 | 0.02423 | 608800.00 | 4207700.00 | 0.02438 |
| 608900.00 | 4207700.00 | 0.02489 | 609000.00 | 4207700.00 | 0.03036 |
| 609200.00 | 4207700.00 | 0.06111 | 609300.00 | 4207700.00 | 0.07823 |
| 609400.00 | 4207700.00 | 0.10957 | 609500.00 | 4207700.00 | 0.14584 |
| 609600.00 | 4207700.00 | 0.16894 | 609700.00 | 4207700.00 | 0.17661 |
| 609800.00 | 4207700.00 | 0.16675 | 609900.00 | 4207700.00 | 0.14880 |
| 610000.00 | 4207700.00 | 0.12997 | 610100.00 | 4207700.00 | 0.11255 |
| 608100.00 | 4207800.00 | 0.01476 | 608200.00 | 4207800.00 | 0.01556 |
| 608300.00 | 4207800.00 | 0.01637 | 608400.00 | 4207800.00 | 0.01850 |
| 608500.00 | 4207800.00 | 0.02102 | 608600.00 | 4207800.00 | 0.02432 |
| 608700.00 | 4207800.00 | 0.02899 | 608800.00 | 4207800.00 | 0.03335 |
| 608900.00 | 4207800.00 | 0.03516 | 609000.00 | 4207800.00 | 0.04019 |
| 609200.00 | 4207800.00 | 0.09919 | 609300.00 | 4207800.00 | 0.15679 |
| 609400.00 | 4207800.00 | 0.20507 | 609500.00 | 4207800.00 | 0.22279 |
| 609600.00 | 4207800.00 | 0.21211 | 609700.00 | 4207800.00 | 0.18341 |
| 609800.00 | 4207800.00 | 0.15291 | 609900.00 | 4207800.00 | 0.12345 |
| 610000.00 | 4207800.00 | 0.10255 | 610100.00 | 4207800.00 | 0.08567 |
| 608100.00 | 4207900.00 | 0.01590 | 608200.00 | 4207900.00 | 0.01667 |
| 608300.00 | 4207900.00 | 0.01771 | 608400.00 | 4207900.00 | 0.01989 |
| 608500.00 | 4207900.00 | 0.02198 | 608600.00 | 4207900.00 | 0.02529 |
| 608700.00 | 4207900.00 | 0.03068 | 608800.00 | 4207900.00 | 0.04029 |
| 608900.00 | 4207900.00 | 0.05514 | 609000.00 | 4207900.00 | 0.06422 |
| 609200.00 | 4207900.00 | 0.30196 | 609300.00 | 4207900.00 | 0.34112 |
| 609400.00 | 4207900.00 | 0.28797 | 609500.00 | 4207900.00 | 0.23029 |
| 609600.00 | 4207900.00 | 0.17639 | 609700.00 | 4207900.00 | 0.13618 |
| 609800.00 | 4207900.00 | 0.10753 | 609900.00 | 4207900.00 | 0.08710 |
| 610000.00 | 4207900.00 | 0.07364 | 610100.00 | 4207900.00 | 0.06410 |
| 608100.00 | 4208000.00 | 0.01380 | 608200.00 | 4208000.00 | 0.01491 |
| 608300.00 | 4208000.00 | 0.01646 | 608400.00 | 4208000.00 | 0.01838 |

608500.00 4208000.00 0.02095 609200.00 4208000.00
0.81880 worker cancer risk
609300.00 4208000.00 0.35041 609400.00 4208000.00
0.20295
609500.00 4208000.00 0.13762 609600.00 4208000.00
0.10335
609700.00 4208000.00 0.08625 609800.00 4208000.00
0.07255
609900.00 4208000.00 0.06514 610000.00 4208000.00
0.05949
610100.00 4208000.00 0.05519 608100.00 4208100.00
0.01112
608200.00 4208100.00 0.01163 608300.00 4208100.00
0.01268
608400.00 4208100.00 0.01404 608500.00 4208100.00
0.01583

*** AERMOD - VERSION 07026 *** *** Gateway HRA impacts P# 18143 A# 17182
*** 05/19/08 ***
*** 14:48:43

*** THE PERIOD ( 8760 HRS) AVERAGE CONCENTRATION VALUES FOR
SOURCE GROUP: CHI_RES ***
INCLUDING SOURCE(S): TURBINA2, TURBINB2, FRPUMP2 ,
*** DISCRETE CARTESIAN RECEPTOR POINTS ***
** CONC OF OTHER IN MICROGRAMS/M**3
**

| X-COORD (M) | Y-COORD (M) | CONC | X-COORD (M) | Y-COORD (M) | CONC |
|---|---|---|---|---|---|
| 609150.00 | 4207550.00 | 0.00400 | 609175.00 | 4207550.00 | 0.00430 |
| 609200.00 | 4207550.00 | 0.00462 | 609225.00 | 4207550.00 | 0.00497 |
| 609250.00 | 4207550.00 | 0.00536 | 609275.00 | 4207550.00 | 0.00579 |
| 609300.00 | 4207550.00 | 0.00626 | 609325.00 | 4207550.00 | 0.00677 |
| 609350.00 | 4207550.00 | 0.00733 | 609375.00 | 4207550.00 | 0.00792 |
| 609400.00 | 4207550.00 | 0.00853 | 609425.00 | 4207550.00 | 0.00918 |
| 609450.00 | 4207550.00 | 0.00985 | 609475.00 | 4207550.00 | 0.01056 |
| 609500.00 | 4207550.00 | 0.01133 | 609525.00 | 4207550.00 | 0.01217 |
| 609550.00 | 4207550.00 | 0.01305 | 609575.00 | 4207550.00 | 0.01398 |
| 609600.00 | 4207550.00 | 0.01502 | 609625.00 | 4207550.00 | 0.01615 |
| 609650.00 | 4207550.00 | 0.01737 | 609675.00 | 4207550.00 | 0.01877 |
| 609700.00 | 4207550.00 | 0.01995 | 609725.00 | 4207550.00 | 0.02118 |
| 609750.00 | 4207550.00 | 0.02249 | 609775.00 | 4207550.00 | 0.02363 |
| 609800.00 | 4207550.00 | 0.02467 | 609825.00 | 4207550.00 | 0.02561 |
| 609850.00 | 4207550.00 | 0.02641 | 609875.00 | 4207550.00 | 0.02708 |
| 609900.00 | 4207550.00 | 0.02760 | 609925.00 | 4207550.00 | 0.02797 |
| 609950.00 | 4207550.00 | 0.02820 | 609975.00 | 4207550.00 | 0.02830 |
| residential chronic HI | | | | | |
| 610000.00 | 4207550.00 | 0.02827 | 610025.00 | 4207550.00 | 0.02813 |
| 610050.00 | 4207550.00 | 0.02789 | 610075.00 | 4207550.00 | 0.02756 |
| 610100.00 | 4207550.00 | 0.02716 | 610125.00 | 4207550.00 | 0.02669 |
| 610150.00 | 4207550.00 | 0.02616 | 610175.00 | 4207550.00 | 0.02560 |
| 610200.00 | 4207550.00 | 0.02500 | 610225.00 | 4207550.00 | 0.02438 |
| 610250.00 | 4207550.00 | 0.02374 | 610275.00 | 4207550.00 | 0.02309 |
| 610300.00 | 4207550.00 | 0.02244 | 610325.00 | 4207550.00 | 0.02180 |
| 610350.00 | 4207550.00 | 0.02116 | 610375.00 | 4207550.00 | 0.02053 |
| 610400.00 | 4207550.00 | 0.01991 | 610425.00 | 4207550.00 | 0.01931 |
| 610450.00 | 4207550.00 | 0.01873 | 610475.00 | 4207550.00 | 0.01819 |
| 610500.00 | 4207550.00 | 0.01767 | 610525.00 | 4207550.00 | 0.01716 |
| 610550.00 | 4207550.00 | 0.01666 | 610575.00 | 4207550.00 | 0.01618 |
| 610600.00 | 4207550.00 | 0.01571 | 610625.00 | 4207550.00 | 0.01525 |
| 610650.00 | 4207550.00 | 0.01481 | 608300.00 | 4207575.00 | 0.00248 |
| 608325.00 | 4207575.00 | 0.00247 | 608350.00 | 4207575.00 | 0.00245 |

| | | | | |
|---|---|---|---|---|
| 608375.00 | 4207575.00 | 0.00244 | 608400.00 | 4207575.00 |
| 0.00242 | | | | |
| 608425.00 | 4207575.00 | 0.00240 | 608450.00 | 4207575.00 |
| 0.00238 | | | | |
| 608475.00 | 4207575.00 | 0.00237 | 608500.00 | 4207575.00 |
| 0.00235 | | | | |
| 608525.00 | 4207575.00 | 0.00233 | 608550.00 | 4207575.00 |
| 0.00231 | | | | |
| 608575.00 | 4207575.00 | 0.00229 | 608600.00 | 4207575.00 |
| 0.00227 | | | | |
| 608625.00 | 4207575.00 | 0.00225 | 608650.00 | 4207575.00 |
| 0.00223 | | | | |
| 608675.00 | 4207575.00 | 0.00221 | 608700.00 | 4207575.00 |
| 0.00219 | | | | |
| 608725.00 | 4207575.00 | 0.00218 | 608750.00 | 4207575.00 |
| 0.00217 | | | | |

```
 *** AERMOD - VERSION 07026 ***     *** Gateway HRA impacts  P# 18143  A# 17182
***         05/19/08
                                    ***
***         14:48:43

                                *** THE PERIOD (  8760 HRS) AVERAGE CONCENTRATION   VALUES FOR
SOURCE GROUP: CHI_WRK  ***
                                    INCLUDING SOURCE(S):      TURBINA4, TURBINB4, FRPUMP4 ,
                                              *** DISCRETE CARTESIAN RECEPTOR POINTS ***
                                        ** CONC OF OTHER    IN MICROGRAMS/M**3
**
```

| X-COORD (M) | Y-COORD (M) | CONC | X-COORD (M) | Y-COORD (M) | CONC |
|---|---|---|---|---|---|
| 608300.00 | 4207750.00 | 0.00060 | 608325.00 | 4207750.00 | 0.00059 |
| 608350.00 | 4207750.00 | 0.00059 | 608375.00 | 4207750.00 | 0.00059 |
| 608400.00 | 4207750.00 | 0.00059 | 608425.00 | 4207750.00 | 0.00058 |
| 608450.00 | 4207750.00 | 0.00058 | 608475.00 | 4207750.00 | 0.00057 |
| 608500.00 | 4207750.00 | 0.00057 | 608525.00 | 4207750.00 | 0.00056 |
| 608550.00 | 4207750.00 | 0.00055 | 608575.00 | 4207750.00 | 0.00055 |
| 608600.00 | 4207750.00 | 0.00054 | 608625.00 | 4207750.00 | 0.00053 |
| 608650.00 | 4207750.00 | 0.00052 | 608675.00 | 4207750.00 | 0.00051 |
| 608700.00 | 4207750.00 | 0.00050 | 608725.00 | 4207750.00 | 0.00050 |
| 608750.00 | 4207750.00 | 0.00049 | 608775.00 | 4207750.00 | 0.00048 |
| 608800.00 | 4207750.00 | 0.00047 | 608825.00 | 4207750.00 | 0.00047 |
| 608850.00 | 4207750.00 | 0.00047 | 608875.00 | 4207750.00 | 0.00047 |
| 608900.00 | 4207750.00 | 0.00048 | 608925.00 | 4207750.00 | 0.00049 |
| 608950.00 | 4207750.00 | 0.00051 | 608975.00 | 4207750.00 | 0.00054 |
| 609000.00 | 4207750.00 | 0.00058 | 609025.00 | 4207750.00 | 0.00063 |
| 609200.00 | 4207750.00 | 0.00126 | 609225.00 | 4207750.00 | 0.00143 |
| 609250.00 | 4207750.00 | 0.00162 | 609275.00 | 4207750.00 | 0.00183 |
| 609300.00 | 4207750.00 | 0.00206 | 609325.00 | 4207750.00 | 0.00230 |
| 609350.00 | 4207750.00 | 0.00256 | 609375.00 | 4207750.00 | 0.00287 |
| 609400.00 | 4207750.00 | 0.00321 | 609425.00 | 4207750.00 | 0.00361 |
| 609450.00 | 4207750.00 | 0.00406 | 609475.00 | 4207750.00 | 0.00454 |
| 609500.00 | 4207750.00 | 0.00505 | 609525.00 | 4207750.00 | 0.00553 |
| 609550.00 | 4207750.00 | 0.00597 | 609575.00 | 4207750.00 | 0.00638 |
| 609600.00 | 4207750.00 | 0.00673 | 609625.00 | 4207750.00 | 0.00698 |
| 609650.00 | 4207750.00 | 0.00720 | 609675.00 | 4207750.00 | 0.00736 |
| 609700.00 | 4207750.00 | 0.00750 | 609725.00 | 4207750.00 | 0.00753 worker chronic HI |
| 609750.00 | 4207750.00 | 0.00747 | 609775.00 | 4207750.00 | 0.00739 |
| 609800.00 | 4207750.00 | 0.00726 | 609825.00 | 4207750.00 | 0.00711 |
| 609850.00 | 4207750.00 | 0.00693 | 609875.00 | 4207750.00 | 0.00674 |
| 609900.00 | 4207750.00 | 0.00653 | 609925.00 | 4207750.00 | 0.00633 |
| 609950.00 | 4207750.00 | 0.00612 | 609975.00 | 4207750.00 | 0.00591 |
| 610000.00 | 4207750.00 | 0.00571 | 610025.00 | 4207750.00 | 0.00551 |

| | | | | | |
|---|---|---|---|---|---|
| 610050.00 | 4207750.00 | 0.00532 | 610075.00 | 4207750.00 | 0.00514 |
| 610100.00 | 4207750.00 | 0.00496 | 610125.00 | 4207750.00 | 0.00478 |
| 610150.00 | 4207750.00 | 0.00461 | 610175.00 | 4207750.00 | 0.00446 |
| 610200.00 | 4207750.00 | 0.00431 | 610225.00 | 4207750.00 | 0.00416 |
| 610250.00 | 4207750.00 | 0.00402 | 610275.00 | 4207750.00 | 0.00389 |
| 610300.00 | 4207750.00 | 0.00376 | 610325.00 | 4207750.00 | 0.00364 |
| 610350.00 | 4207750.00 | 0.00354 | 610375.00 | 4207750.00 | 0.00344 |
| 610400.00 | 4207750.00 | 0.00334 | 610425.00 | 4207750.00 | 0.00325 |

```
 *** AERMOD - VERSION 07026 ***     *** Gateway HRA impacts  P# 18143  A# 17182
***        05/19/08
                                    ***
***        14:48:43

                                *** THE   1ST HIGHEST  1-HR AVERAGE CONCENTRATION   VALUES FOR
SOURCE GROUP:  AHI       ***
                                INCLUDING SOURCE(S):      TURBINA5, TURBINB5,
                                          *** DISCRETE CARTESIAN RECEPTOR POINTS ***
                                     ** CONC OF OTHER    IN MICROGRAMS/M**3
**

     X-COORD (M)  Y-COORD (M)        CONC     (YYMMDDHH)              X-COORD (M)  Y-COORD (M)
CONC     (YYMMDDHH)
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
- - - - - - - - - - - - - - - - -
       609242.50   4207936.00        0.02645  (05071112)                609242.19   4207911.50
0.03635  (05071111)
       609241.81   4207886.50        0.04588  (05071111)                609241.50   4207862.00
0.05265  (05071111)
       609241.12   4207837.00        0.05602  (05071111) acute HI       609240.75   4207812.50
0.05570  (05071111)
       609240.44   4207787.50        0.05190  (05071111)                609240.06   4207762.50
0.04561  (05071111)
       609239.69   4207738.00        0.03868  (05071111)                609239.38   4207713.00
0.03176  (05071111)
       609239.00   4207688.50        0.02548  (05071111)                609265.50   4208548.00
0.01255  (05042712)
       609244.62   4208582.00        0.01363  (05042714)                609214.19   4208597.00
0.01466  (05042715)
       609275.62   4208506.00        0.01076  (05050911)                609275.31   4208481.50
0.01103  (05050911)
       609274.94   4208456.50        0.01087  (05050911)                609274.56   4208432.00
0.01022  (05050911)
       609274.25   4208407.00        0.00972  (05052814)                609273.88   4208382.00
0.00891  (05052814)
       609273.50   4208357.50        0.00885  (05052812)                609273.19   4208332.50
0.00891  (05052812)
       609272.81   4208308.00        0.00922  (05050512)                609272.44   4208283.00
0.00977  (05050512)
       609272.12   4208258.00        0.00895  (05050512)                609271.75   4208233.50
0.00745  (05061609)
       609271.38   4208208.50        0.00576  (05061609)                609271.06   4208184.00
0.00496  (05083115)
       609270.69   4208159.00        0.00540  (05083115)                609270.38   4208134.00
0.00535  (05083115)
       609270.00   4208109.50        0.00544  (05071214)                609269.62   4208084.50
0.00709  (05112212)
       609269.31   4208060.00        0.00916  (05112212)                609268.94   4208035.00
0.01138  (05112212)
       609268.56   4208010.50        0.01353  (05112212)                609268.25   4207985.50
0.01558  (05112212)
       609267.88   4207960.50        0.01856  (05071210)                609267.50   4207936.00
0.02382  (05071210)
       609267.19   4207911.00        0.02723  (05071210)                609266.81   4207886.50
0.03319  (05071111)
       609266.44   4207861.50        0.04257  (05071111)                609266.12   4207836.50
0.05009  (05071111)
       609265.75   4207812.00        0.05464  (05071111)                609265.38   4207787.00
0.05521  (05071111)
       609265.06   4207762.50        0.05263  (05071111)                609264.69   4207737.50
0.04782  (05071111)
       609264.38   4207712.50        0.04187  (05071111)                609264.00   4207688.00
0.03563  (05071111)
       609289.81   4208549.00        0.01216  (05042712)                609267.50   4208585.50
0.01360  (05042714)
       609223.94   4208619.50        0.01528  (05042715)                609181.44   4208615.00
0.01597  (05042715)
       609300.62   4208506.00        0.01165  (05050911)                609300.25   4208481.00
0.01167  (05050911)
       609299.94   4208456.00        0.01123  (05050911)                609299.56   4208431.50
0.01106  (05052814)
       609299.25   4208406.50        0.01070  (05052814)                609298.88   4208382.00
0.00955  (05052814)
       609298.50   4208357.00        0.01003  (05052812)                609298.19   4208332.00
0.00989  (05052812)
       609297.81   4208307.50        0.01078  (05050512)                609297.44   4208282.50
0.01112  (05050512)
       609297.12   4208258.00        0.01013  (05050512)                609296.75   4208233.00
0.00842  (05061609)
```

| | | | | | | |
|---|---|---|---|---|---|---|
| 609296.38 | 4208208.50 | 0.00669 | (05061609) | 609296.06 | 4208183.50 | 0.00545 (05083115) |
| 609295.69 | 4208158.50 | 0.00598 | (05083115) | 609295.31 | 4208134.00 | 0.00604 (05083115) |
| 609295.00 | 4208109.00 | 0.00565 | (05083115) | 609294.62 | 4208084.50 | 0.00710 (05071214) |
| 609294.25 | 4208059.50 | 0.00902 | (05112212) | 609293.94 | 4208034.50 | 0.01114 (05112212) |
| 609293.56 | 4208010.00 | 0.01322 | (05112212) | 609293.25 | 4207985.00 | 0.01524 (05112212) |
| 609292.88 | 4207960.50 | 0.01703 | (05112212) | 609292.50 | 4207935.50 | 0.01963 (05071210) |
| 609292.19 | 4207910.50 | 0.02505 | (05071210) | 609291.81 | 4207886.00 | 0.02856 (05071210) |
| 609291.44 | 4207861.00 | 0.03026 | (05081111) | 609291.12 | 4207836.50 | 0.03853 (05071111) |

# Appendix D

## BACT Cost-Effectiveness Data

ONSITE SYCOM Energy Corporation

# Cost Analysis of $NO_x$ Control Alternatives for Stationary Gas Turbines

**Contract No. DE-FC02-97CHIO877**

*Prepared for:*

**U.S. Department of Energy**
Environmental Programs
Chicago Operations Office
9800 South Cass Avenue
Chicago, IL 60439

*Prepared by:*

**ONSITE SYCOM Energy Corporation**
701 Palomar Airport Road,
Suite 200
Carlsbad, California 92009

October 15, 1999

# TABLE A-5
# 1999 CONVENTIONAL SCR COST COMPARISON

| | | | | 5 MW Class | 25 MW Class | 150 MW Class |
|---|---|---|---|---|---|---|
| Turbine Model | | | | Solar Centaur 50 | GE LM2500 | GE Frame 7FA |
| Turbine Output | | | | 4.2 MW | 23 MW | 151 MW |
| Direct Capital Costs (DC): | | | Source | | | |
| Purchased Equip. Cost (PE): | | | MHIA | | | |
| Basic Equipment (A): | | | MHIA | $240,000 | $660,000 | $2,100,000 |
| Ammonia injection skid and storage | 0.00 x A | | MHIA | included | included | included |
| Instrumentation | 0.00 x A | | OAQPS | included | included | included |
| Taxes and freight: | 0.08 A x B | | OAQPS | $19,015 | $52,746 | $169,530 |
| PE Total: | | | | $256,704 | $712,086 | $2,288,649 |
| Direct Installation Costs (DI):* | | | | | | |
| Foundation & supports: | 0.08 x PE | | OAQPS | $20,536 | $56,965 | $183,092 |
| Handling and erection: | 0.14 x PE | | OAQPS | $35,939 | $99,689 | $320,411 |
| Electrical: | 0.04 x PE | | OAQPS | $10,268 | $28,483 | $91,546 |
| Piping: | 0.02 x PE | | OAQPS | $5,134 | $14,241 | $45,773 |
| Insulation: | 0.01 x PE | | OAQPS | $2,567 | $7,121 | $22,886 |
| Painting: | 0.01 x PE | | OAQPS | $2,567 | $7,121 | $22,886 |
| DI Total: | | | | $77,011 | $213,620 | $686,595 |
| DC Total: | | | | $333,716 | $925,686 | $2,975,244 |
| Indirect Costs (IC): | | | | | | |
| Engineering: | 0.10 x PE | | OAQPS | $25,670 | $71,207 | $100,000 |
| Construction and field expenses: | 0.05 x PE | | OAQPS | $12,835 | $35,603 | $114,432 |
| Contractor fees: | 0.10 x PE | | OAQPS | $25,670 | $71,207 | $228,865 |
| Start-up: | 0.02 x PE | | OAQPS | $5,134 | $14,241 | $45,773 |
| Performance testing: | 0.01 x PE | | OAQPS | $2,567 | $7,121 | $22,886 |
| Contingencies: | 0.03 x PE | | OAQPS | $7,701 | $21,362 | $68,659 |
| IC Total: | | | | $79,578 | $220,741 | $580,616 |
| Total Capital Investment (TCI = DC + IC): | | | | $413,294 | $1,146,427 | $3,555,861 |
| Direct Annual Costs (DAC): | | | | | | |
| Operating Costs (O): | 24 hrs/day, 7 days/week, 50 weeks/yr | | | | | |
| Operator: | 0.5 hr/shift | 25 $/hr for operator pay | OAQPS | $13,125 | $13,125 | $13,125 |
| Supervisor: | 15% of operator | | OAQPS | $1,969 | $1,969 | $1,969 |
| Maintenance Costs (M): | | | | | | |
| Labor: | 0.5 hr/shift | 25 $/hr for labor pay | OAQPS | $13,125 | $13,125 | $13,125 |
| Material: | 100% of labor cost | | OAQPS | $13,125 | $13,125 | $13,125 |
| Utility Costs: | 0% thermal eff | 800 (F) operating temp | | | | |
| Gas usage | 0.0 (MMcf/yr) | 1,000 (Btu/ft3) heat value | | | | |
| Gas cost | 3.000 ($/MMcf) | | variable | | | |
| Perf. loss: | 0.5% | | | | | |
| Electricity cost | 0.06 ($/kwh) performance loss cost penalty | | variable | $10,584 | $57,960 | $405,720 |
| Catalyst replace: | assume 30 ft³ catalyst per MW, $400/ft³, 7 yr. life | | MHIA | $10,352 | $58,690 | $396,833 |
| Catalyst dispose: | $15/ft³*30 ft³/MW*MW*.2054 (7 yr amortized) | | OAQPS | $388 | $2,126 | $14,881 |
| Ammonia: | 360 ($/ton) [tons $NH_3$ = tons $NO_x$ * (17/46)] | | variable | $3,510 | $14,820 | $108,257 |
| $NH_3$ inject skid: | 5 (kW) blower | 5 kw ($NH_3/H_2O$ pump) | MHIA | $5,040 | $7,560 | $27,720 |
| Total DAC: | | | | $71,219 | $180,500 | $994,755 |
| Indirect Annual Costs (IAC): | | | | | | |
| Overhead: | 60% of O&M | | OAQPS | $24,806 | $24,806 | $24,806 |
| Administrative: | 0.02 x TCI | | OAQPS | $8,268 | $22,929 | $71,117 |
| Insurance: | 0.01 x TCI | | OAQPS | $4,133 | $11,464 | $35,559 |
| Property tax: | 0.01 x TCI | | OAQPS | $4,133 | $11,464 | $35,559 |
| Capital recovery: | 10% interest rate, 0.13 x TCI | 15 yrs - period | OAQPS | $52,976 | $143,272 | $415,329 |
| Total IAC: | | | | $94,314 | $213,935 | $582,370 |
| Total Annual Cost (DAC + IAC): | | | | $165,533 | $394,435 | $1,577,125 |
| $NO_x$ Emission Rate (tons/yr) at 42 ppm: | | | | 33.4 | 141.0 | 1030.0 |
| $NO_x$ Removed (tons/yr) at 9 ppm, | | 79% removal efficiency | | 26.4 | 111.4 | 813.7 |
| **Cost Effectiveness ($/ton):** | | | | **$6,274** | **$3,541** | **$1,938** |
| **Electricity Cost Impact (¢/kwh):** | | | | **0.469** | **0.204** | **0.117** |

*Assume modular SCR is inserted into existing HRSG spool piece

# REVISED
# BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

## TOWANTIC ENERGY PROJECT

FEBRUARY 2000

R·W·BECK

1998). This value is derived by a formula specified by CTDEP. The Project's maximum emission rate will be 10 ppm, or 43 percent of the allowable MASC limit.

The use of an SCR for $NO_x$ control in combination with an oxidation catalyst for control of CO may increase particulate emissions in the form of ammonium bi-sulfates. Due to the insignificant amount of sulfur in natural gas fuel this impact will be extremely small. During oil-fired operation (the Project will be limited to 720 hours per year of oil-fired operation) the estimated amount of ammonium bi-sulfate emissions will increase particulate emissions by approximately 60 pounds per hour. This increase has only a minor effect on the maximum predicted air quality impacts from the Project, which are well within National Ambient Air Quality Standards.

An environmental benefit of SCR, when combined with a CO Oxidation Catalyst (Section 1.3), is a decrease in emissions of VOCs. Although the Project is not required to include VOCs in the PSD review as discussed in Section 1.1, the use of an SCR and CO Oxidation Catalyst will ensure that VOC emissions are minimal. The reduction in VOC emissions from SCR/CO Oxidation Catalyst is comparable to that from $SCONO_x$™.

#### ENERGY ANALYSIS

Use of SCR for $NO_x$ control has an energy penalty due to the energy required to force combustion gases through the SCR reactor. There are other energy requirements associated with chemical transport and operation of equipment, pumps and motors but these are relatively small. Operation of the SCR for the Towantic Project is estimated to reduce electrical output by 1.46 MW or 11,510 MWh of electricity per year[1]. Not only is the electrical output reduced but the fuel use is increased by 135,800 MCF of gas per year.

#### 1.2.4.1.3 ECONOMIC ANALYSIS

Table 3 presents the capital and annualized cost for the SCR control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst), energy penalties and ammonia. All costs are for two GE Frame 7FA gas turbine units, each including one HRSG, which includes the SCR unit.

[1] Based on annual capacity factor of 90%.

issues, poses a serious concern as to whether the Project could secure final construction approval from the Council.

As with the SCR/CO Oxidation Catalyst, SCONO$_x$™ will reduce VOC emissions along with NO$_x$ and CO. The Project is not required to include VOCs in the PSD review, as discussed in Section 1.1, however, SCONO$_x$™ does have the added benefit of decreasing VOC emissions. The reduction in VOC emissions from SCONO$_x$™ is comparable to that from SCR/CO Oxidation Catalyst.

#### 1.2.4.2 .2 ENERGY ANALYSIS

Use of SCONO$_x$™ for NO$_x$ control has an energy penalty due to the energy required to force combustion gases through the SCONO$_x$™ reactor (pressure drop). Pressure drop through the SCONO$_x$™ unit is estimated at 5.25 inches by the manufacturer. This is compared to approximately 3.5 inches of pressure drop for a combined SCR and CO catalyst installed in a HRSG. The pressure drop of 5.25 inches reduces the total plant output by approximately 2.19 MW or 17,266 MWh per year. Not only is the electrical output reduced but the fuel use is increased by 202,200 MCF of gas per year.

Production of the steam used in the regeneration process also imposes a penalty in that the steam is not available to generate electricity. Based on the manufacturer's estimate of low-pressure steam requirements of 15,000 pounds per hour at 600°F and 20 psig, the steam turbine capability of the Project will be reduced by approximately 2.5 MW or 19,710 MWh per year.

The additional energy requirements of the SCONO$_x$™ system (relative to other NO$_x$ control technology) means that the incremental amount of energy will not be supplied by the Project to meet energy needs in the service area. Other power plants will make-up the difference (approximately 4.2 MW) and this will result in a proportional increase in air pollution emissions. These other power plants may emit at levels equal to or greater than the Project.

As with any mechanical system, there are energy requirements associated with the operation of equipment, pumps and motors but these are relatively small. Finally, the SCONO$_x$™ system consumes 200 pounds per hour of natural gas total for regeneration of the catalyst plus leakage. This results in an annual natural gas consumption of 41,800 MCF.

#### 1.2.4.2.3 ECONOMIC ANALYSIS

Table 4 presents the capital and annualized cost for the SCONO$_x$™ control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst) and energy costs. These costs are based on general information provided during a meeting with representatives from ABB Environmental. ABB Environmental was not able to provide a specific cost quote for a SCONO$_x$™ system for a GE 7FA combustion turbine with a HRSG. The projected capital costs are based on a SCONO$_x$™ system designed for an ABB GT-24 unit adjusted for the GE 7FA. The SCONO$_x$™ system also reduces

**Notice Inviting Written Public Comment on Proposed Air Quality Permit**

The Bay Area Air Quality Management District ("District") is proposing to issue an amended Authority to Construct and Prevention of Significant Deterioration ("PSD") Permit for the **Gateway Generating Station** (formerly known as Mirant Contra Costa Generating Station Unit 8). Before doing so, the District is providing the public with notice of its proposal and an opportunity to review and comment on the proposed permit.

The Gateway Generating Station is a 530-MW natural gas fired merchant power plant to be located at 3223 Wilbur Avenue in Antioch, CA. The power plant will be owned and operated by Pacific Gas & Electric Co. and will consist of two combustion turbine generators, two heat recovery steam generators, a steam turbine generator and associated equipment, a dry cooling system, a natural gas fired preheater, an oil-water separator, and a diesel fire pump. The District initially issued a permit for the project in 2001. The permit now needs to be amended to reflect certain changes in project design.

Under the proposed amended authority to construct, the facility would be allowed to emit up to the following maximum quantities of regulated air pollutants:

Nitrogen Oxides (NOx): 174.3 tons per year
Carbon Monoxide (CO): 554.3 tons per year
Precursor Organic Compounds (POC): 46.6 tons per year
Particulate Matter (PM): 101.7 tons per year
Sulfur Dioxide: ($SO_2$): 37.0 tons per year

The project will utilize the Best Available Control Technology to minimize emissions of these air pollutants as required by District Regulation 2-2-301. The project will also offset its emissions of NOx and POC by surrendering emissions reduction credits as required by District Regulation 2-2-302. The proposed project will consume a less-than-significant degree of PSD increment, and a full PSD increment consumption analysis is not required.

Further information about the project and how it will comply with applicable regulatory requirements is available in the District's Engineering Evaluation for the proposed amended permit. The Engineering Evaluation, proposed permit conditions, and all supporting materials are available for public inspection at the Outreach and Incentives Division Office located on the 5th Floor of District Headquarters, 939 Ellis Street, San Francisco, CA, 94109. The Engineering Evaluation and proposed permit conditions are also available on the District's website at www.baaqmd.gov.

The District invites all interested parties to comment on any aspect of the proposed amended Authority to Construct and draft amended PSD Permit pursuant to District Regulation 2-2-405 and 40 C.F.R. Section 124.10. Comments should be made in writing and directed to Brian K. Lusher, Air Quality Engineer, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA, 94109, (415) 749-4623, blusher@baaqmd.gov, and must be received by July 14, 2008. During the comment period, interested parties may also request that the District hold a public hearing on its proposal. A request for a public hearing must be in writing and must state the nature of the issues proposed to be raised at the hearing. The District will review any requests for a public hearing and will hold a hearing if it finds, on the basis of the requests, a significant degree of public interest in the permit exists.

Dated at San Francisco, the 4th of June.

Signed by Jack P. Broadbent
Jack P. Broadbent
Executive Officer/APCO
Bay Area Air Quality Management District

# Exhibit No. 322

PG&E Brief on Jurisdictional Issues and Motion for Summary Disposition (Dismissal) submitted to US EPA Environmental Appeals Board, dated and filed July 2, 2009, including Declaration of Gary S. Rubenstein, dated July 1, 2009, filed July 2, 2009

**BEFORE THE ENVIRONMENTAL APPEALS BOARD**
**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**WASHINGTON, D.C.**

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| In the Matter Of:<br>Gateway Generating Station | PSD Appeal No. 09-02 |

**INTERVENOR PACIFIC GAS AND ELECTRIC COMPANY'S**
**BRIEF ON JURISDICTIONAL ISSUES**
**AND MOTION FOR SUMMARY DISPOSITION (DISMISSAL)**

This Brief on Jurisdictional Issues and Motion for Summary Disposition is submitted in response to the June 18, 2009 Environmental Appeals Board ("EAB" or "Board") Order requesting briefing on jurisdictional issues in this Appeal. This matter commenced with the filing by Petitioner Rob Simpson ("Petitioner") of a Petition for Review ("Petition") challenging the Prevention of Significant Deterioration ("PSD") permit for the Gateway Generating Station ("Gateway" or "the facility"), located at 3225 Wilbur Avenue in Antioch, California and owned and operated by the Pacific Gas and Electric Company ("PG&E"). The Bay Area Air Quality Management District ("BAAQMD" or "District"), pursuant to authority delegated to the District by EPA, issued the PSD permit to the facility on July 24, 2001 as part of a single, comprehensive "Authority to Construct" ("ATC") permit (Application Number 1000).[1] The Gateway facility is currently operating pursuant to, and in full compliance with, that validly issued PSD permit. While PG&E maintains that it is in compliance with all applicable state and federal laws, as

[1] BAAQMD's practice is to track permits by application number, rather than assign a number upon issuance of the permit. (*See* Declaration of Gary Rubenstein, ("R. Decl.") submitted herewith, at ¶ 9.)

described in PG&E's May 27 Motion for Stay, EPA has informed PG&E that Gateway may not be in full compliance with the PSD program due to certain events that occurred before PG&E became the owner of the facility.

On May 27, 2009 PG&E filed a Motion to Intervene and a Motion for Stay of this matter, to allow time for EPA's enforcement process to proceed and potentially resolve certain issues relevant to this Petition. Also on May 27, 2009, BAAQMD filed a "Joinder in PG&E's Motion to Stay Proceedings". On June 18, 2009, the EAB issued an Order ("EAB Order"): (1) granting PG&E's Motion to Intervene; (2) denying PG&E's Motion for Stay; and, (3) requesting briefing on the following three points:

a) whether any appeal from the original Authority to Construct would be timely;

b) whether the EAB would have jurisdiction over an appeal from the Authority to Construct; and

c) whether there is any other jurisdictional basis for this appeal.

The answer to each of the EAB's three questions is "no." Petitioner cannot satisfy his burden to demonstrate that the Petition is timely or within the EAB's jurisdiction. Specifically, and with respect to the issues on which the EAB requested briefing: (1) to the extent that Petitioner is attempting to request review of the original, 2001 ATC and PSD permit, the Petition is untimely; (2) the EAB does not have jurisdiction over an appeal of the state law ATC, although it would have jurisdiction to review a timely appeal of the PSD elements of a District-issued permit had such an appeal been filed and satisfied EAB's jurisdictional requirements; and (3) any other allegations by Petitioner, e.g., that the Gateway facility is not operating in compliance with the terms and conditions of its permits and/or without a valid District-issued Permit to Operate, are without merit and, in any event, are outside the purview of the EAB.

For these reasons, as set forth more fully below, PG&E respectfully requests that the EAB determine that it has no jurisdiction over the instant Appeal, and that the Petition be summarily dismissed.

## I. BACKGROUND

Pursuant to the Clean Air Act and EPA regulations, BAAQMD implements the federal PSD permit program in the San Francisco Bay Area. *See* Clean Air Act ("CAA") §§ 107(a), 110; 42 U.S.C. §§ 7407(a), 7410; 40 C.F.R. § 52.21(u). The District administers the PSD permit program through a contractual "delegation agreement" with EPA. *See, e.g.,* "U.S. EPA-Bay Area AQMD Agreement for Delegation of Authority for Prevention of Significant Deterioration of Air Quality Program (40 CFR 52.21)," dated April 23, 1986, (R. Decl., Exh. A.). In delegating to the District the authority to administer the PSD permit program, EPA determined that District Regulation 2, Rule 2 "generally meets the requirements of 52.21; therefore, *District Authorities to Construct (ATCs or permits) will be deemed to meet Federal PSD permit requirements. . . .*" *Id.*, emphasis added. Pursuant to the terms of this delegation agreement, the District issues a single permit that functions as both a District ATC and a PSD permit. *See also* District Regulations 2-2-101, 2-2-304, R. Decl., Exh. B.)

Pursuant to District regulations, on July 24, 2001 the District issued an ATC for the facility (R. Decl., ¶ 9, Exh. C, pp. 1, 23-36).[2] Consistent with the PSD delegation agreement, the ATC included the PSD permit.[3] *Id.* Construction of the

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[2] The ATC was issued to Mirant Delta, LLC, which originally owned the facility, and at the time the ATC was issued referred to the facility as Contra Costa Unit 8. PG&E acquired the facility on November 30, 2006 and BAAQMD transferred the District permit (including the PSD permit) to PG&E on January 4, 2007. (R. Decl. at ¶¶ 1, 9.) In some documents, EPA refers to the facility as the "Delta Power Plant." After acquiring the facility, PG&E renamed the facility the Gateway Generating Station. For consistency, the project will be referred to as "Gateway" or "the facility" in this Brief.

[3] The EPA-BAAQMD PSD delegation agreement in effect at the time that BAAQMD issued the facility's permit was the April 23, 1986 agreement, (R. Decl. at ¶ 3, Exh. A). For various reasons (continued...)

facility commenced in 2001. (R. Decl. at ¶ 10.) The facility's prior owner suspended construction of the facility during August 2002. PG&E took over ownership of the facility on November 30, 2006, and recommenced construction in February 2007. (R. Decl. at ¶¶ 1, 10.) Pursuant to BAAQMD regulations, the facility timely filed requests to extend the ATC/PSD permit. (R. Decl. at ¶ 10.) As noted in BAAQMD's Brief on Jurisdictional Issues, filed July 1, 2009 ("BAAQMD Brief"), the District "intended that [the District permit extensions] would be effective to extend the PSD permit. (BAAQMD Brief, pp. 3, 11.)[4]

On December 18, 2007, PG&E submitted to BAAQMD an application to amend certain emission limits in the PSD permit relating primarily to commissioning and start-up procedures. (R. Decl. at ¶ 11, Exh. F.) The District prepared a draft amended permit and circulated that draft for public comment. (*See* Petition for Review ("Pet.") at Exh. 2B.) However, after the close of the public comment period and before the District took final action, by letter dated February 13, 2009, PG&E withdrew its permit amendment application because PG&E determined that it could comply with the original permit conditions. (R. Decl. at ¶ 12, Exh. G.) Since PG&E

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(...continued)
related to changes in state and federal law, in 2004, EPA re-delegated limited PSD authority to the District. (R. Decl. at ¶ 4, Exh. D.) The current version of the PSD delegation agreement is dated February 4, 2008. (R. Decl. at ¶ 5, Exh. E.)

[4] PG&E notes that whether the PSD permit was properly, or needed to be, "extended," by either BAAQMD or EPA, is not the issue in this case. First, PG&E unequivocally disagrees with any implication that the facility's PSD permit expired or that all of "the parties" are in agreement on this point. (BAAQMD Brief at p. 11.) Second, PG&E disagrees with any representation made by the District that Gateway's current PSD permit is not valid or was not validly extended, should extensions have been necessary. The District acknowledges that, until early 2009, the District believed that the facility's permit had been appropriately extended. (BAAQMD Brief at pp. 3-4, 11, Exh. C.) PG&E agrees with the District's previous position that if the PSD permit did need to be extended, the District effectuated such extensions by extending the ATC, pursuant to the EPA-BAAQMD delegation agreements. (BAAQMD Brief at pp. 3, 11.) Indeed, in June 2004, months after the PSD permit allegedly "expired", EPA re-delegated authority to the District to administer the PSD permit for the facility—which was specifically named in the agreement—and gave no indication that Gateway's permit was no longer valid. (R. Decl. ¶ 4, Exh. D, pp. 1-8) Any present interpretation by EPA that the PSD permit expired is certainly, as the District characterizes it, "revised guidance." (BAAQMD Brief at p. 11, n. 9.) While this presents interesting history and context, any controversy over the validity of extension of the facility's PSD permit is an enforcement matter, and therefore, not within the EAB's jurisdiction.

withdrew its application, the District did not amend the PSD permit. PG&E is operating the Gateway facility in conformance with the terms and conditions of the original, unmodified PSD permit, and with all other applicable regulatory requirements.

## II. PETITIONER IS BARRED FROM SEEKING REVIEW OF THE ORIGINAL PSD PERMITTING DECISION.

As stated in the EAB Order, "the petitioner has the burden to set forth, in the petition, the basis for appeal and the threshold jurisdictional requirements." (EAB Order at p. 5.) The Petition in this case fails to meet even the most generous interpretation of this standard. Indeed, Petitioner concedes his "failure to participate in the permit process." (Pet. at p. 7.) For these reasons, as set forth in more detail below, the EAB's initial impression, expressed in the EAB Order, that "the EAB lacks jurisdiction over this matter" is correct. (EAB Order at p. 4.) Therefore, the Petition should be dismissed.

### A. The District issued a valid PSD permit to Gateway.

Petitioner and the EAB have questioned whether the facility ever had a PSD permit (Pet. at 11; EAB Order at p.3, n.2.), with Petitioner claiming that "the District has offered no evidence that they ever issued a PSD permit for this facility." However, Petitioner himself states that District Assistant Counsel Alexander Crockett informed him that the District issued the facility a state-law ATC and a federal PSD permit in 2001. (Pet. at 11.) The record clearly demonstrates that BAAQMD issued an ATC/PSD permit for the facility in 2001, supporting these statements by the District. (R. Decl. ¶¶ 1, 3, 8, 9, Exh. C, July 24, 2001 ATC, citing "PSD" as the basis for certain permit conditions.)[5]

[5] *See, e.g.*, Condition 14: "The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,227 MM Btu per hour, averaged over any rolling 3-hour period. (*PSD for NOx*)" (*Emphasis added.*)

Issuance of the PSD permit was coordinated with the state's process for permitting power plants.[6] On October 23, 2000, BAAQMD issued a Preliminary Determination of Compliance ("PDOC") for the facility. The PDOC serves as the draft statement of basis for both the ATC and the PSD permit. In issuing the draft statement of basis, the District described the scope of the permitting action and requested public comment:

> Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Preliminary Determination of Compliance (PDOC) document for the CCPP Unit 8. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #1000. *The PDOC describes how the proposed facility will comply with applicable federal,* state, and BAAQMD *regulations*, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. *This document includes* a health risk assessment that estimates the impact of the project emissions on public health and *a PSD air quality impact analysis,* which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.
> Pursuant to Regulation 2, Rule 3, Section 404, this PDOC is subject to the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

(R. Decl., Exh. H, p. 1, emphasis added.)

The PDOC and the Final Determination of Compliance ("FDOC"), issued on February 2, 2001, each provide a complete PSD analysis, including a BACT analysis and a PSD air quality impact analysis. The FDOC also incorporates comments that were received during the public comment period for the PDOC, and demonstrates that the District satisfied the required public process. (R. Decl., Exh. I, p. 8.) The PDOC, FDOC, and the facility's permit list numerous permit conditions

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[6] The District's process for permitting power plants is integrated with the California Energy Commission's ("CEC's") certification process. Where the District would normally issue a "Statement of Basis" for a permitting decision, it instead issues a "Determination of Compliance." *See* District Regulation 2, Rule 3. The District will issue an ATC for a power plant only after the CEC's certification process is complete, and only if the certification incorporates the District's permit conditions. *See* District Regulation 2-3-301.

as "PSD" conditions; thus, making it clear that Gateway has a validly issued PSD permit. (R. Decl., Exhs. C, H, I.)

B. The Petition for Review is Untimely.

As the facility was validly issued a PSD permit in 2001, any challenge to that permitting activity is untimely. Pursuant to 40 C.F.R. Part 124.19(a), a Petitioner has 30 days after a final permit decision to file a petition with the EAB. It has been approximately eight years since BAAQMD issued a final PSD permit to the facility in July, 2001. The Petitioner has not explained how the EAB could have jurisdiction over a final permitting decision that is eight years old. Indeed, Petitioner cannot do so, as the EAB has consistently held that "[it] is a petitioner's responsibility to ensure that filing deadlines are met, and the Board will generally dismiss petitions for review that are received after a filing deadline." *See EAB Practice Manual*, p.32, citing *In re AES Puerto Rico, L.P.,* 8 E.A.D. 324, 329 (EAB 1999), *aff'd, Sur Contra La Contaminacion v. EPA,* 202 F.3d 443 (1st Cir. 2000) (limited extensions granted due to delays cause by a hurricane); *In re Kawaihae Cogeneration Project,* 7 E.A.D. 107 (EAB 1997). The EAB strictly construes the filing deadline and has relaxed the requirement only in extraordinary circumstances. *See In re Town of Marshfield, Mass,* NPDES Appeal No. 07-03, slip op. at 8 (EAB, Mar. 27, 2007); *In the Matter of Georgetown Steel Corp.,* 3 E.A.D. 607 (EAB 1991). Even so, the EAB's rare relaxation of the filing requirement has, at most, involved an extension of a matter of weeks – certainly not years as would be the situation here.

C. Petitioner Does Not Have Standing

Even if the EAB waives the requirement for timeliness, Section 124.19(a) grants standing only to a "person who filed comments on that draft permit or participated in the public hearing." Petitioner did neither, and has not provided any evidence that he participated or sought to participate in the facility's 2001 PSD permitting process in any manner. Petitioner therefore does not have standing to

challenge the PSD permit.

Petitioner asserts that he is exempt from the ordinary standing requirement, based on the EAB's recent decision regarding the Russell City Energy Center.[7] See, *In re Russell City Energy Center*, Slip Opinion, PSD Appeal No. 08-01 (July 29, 2008) ("*Russell City*"). Petitioner's reliance on the *Russell City* decision is wholly misplaced. In its *Russell City* opinion, the EAB based the decision to remand the permitting action on the specific circumstances where the EAB found proper public notice to be lacking. In *Russell City*, the Petitioner pled substantial facts describing the District's failure to involve itself in the process of noticing the draft permit and in the District's failure to address – or even record – comments on the draft permit. *Russell City*, 29, 35-37. Other than quoting from the *Russell City* opinion, Petitioner has not described or demonstrated that the District's notice of the PSD permit in 2001 was at all faulty.

Even if Petitioner attempts to demonstrate that the District's 2001 PSD permitting process for the Gateway facility was deficient and that the deficiency should excuse Petitioner's failure to participate (as in *Russell City*), in *Russell City* Petitioner's Appeal was filed only about 63 days after the permit was issued (about 33 days after the appeal deadline). Here, the permit was issued eight years ago. The sheer length of time that has passed here obviates any possible extraordinary circumstances that might justify Petitioner's late filing and lack of participation.

## III. THE EAB DOES NOT HAVE JURISDICTION TO REVIEW THE DISTRICT-ISSUED ATC

The permit issued to the facility in 2001 was a joint ATC/PSD permit. To the extent that the Petitioner may be appealing the 2001 ATC or later versions of the District-only portions of the facility's permit, the EAB does not have jurisdiction over

[7] Mr. Simpson was also the Petitioner in the Russell City case.

such an appeal.

The FDOC issued by the District in February 2001 specifically states that the document addresses federal, state and local requirements in addition to PSD requirements: "The FDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation." (R. Decl., Exh. I, p. 1) and "The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations " (R. Decl., Exh. I, p. 23). The FDOC addresses areas that are not part of the PSD program, specifically, emissions offsets, which are required for nonattainment areas under New Source Review but are clearly not part of a PSD program (R. Decl., Exh. I, pp. 15-17); a health risk assessment, to address the District's Health Risk Assessment Policy (R. Decl., Exh. I, p. 18); other District rules and regulations (such as prohibitory rules) (R. Decl., Exh. I, pp. 19-22); and requirements of the California Environmental Quality Act (R. Decl., Exh. I, p. 22). Finally, the conditions of the ATC cite their basis, and many if not most of the conditions are based on regulatory requirements other than the requirements of the PSD program. For example, there is a condition limiting ammonia, which is not a pollutant that is regulated under PSD. The basis for the ammonia limit is cited as "TRMP[8] for $NH_3$" (R. Decl., Exh. C, p. 9; Exh. I, p. 28).

The EAB's jurisdiction and authority to adjudicate permit appeals arises from 40 C.F.R. Part 124.19. This section provides for the "Appeal of RCRA, UIC, NPDES, and PSD Permits." State law permits are not included within the EAB's jurisdiction. *See In re Sutter Power Plant*, 8 E.A.D. 680, 688 (EAB 1999) ("[t]he Board will deny review of issues that are not governed by the PSD regulations because it lacks jurisdiction over them."); *see also In re Tondu Energy Co.*, 9

[8] "TRMP" is the District's Toxic Risk Management Program

E.A.D. 710, 719 (EAB 2001) ("State law claims are not grounds for review.") (citing cases). Hence, the various non-PSD permit provisions summarized above, which comprise the majority of the ATC, are not subject to EAB review.

## IV. BAAQMD DID NOT AMEND THE GATEWAY PSD PERMIT, SO THERE IS NO RECENT PSD PERMIT ACTION FOR THE EAB TO REVIEW.

The Petition for Review requests that the EAB remand the PSD permit to BAAQMD, apparently in order to enable the Petitioner to participate in a public review and comment process for a permit amendment application that was withdrawn.[9] Even assuming that Petitioner's asserted inability to participate in the public process for the District's previously proposed Gateway permit amendment was due to inadequate notice, Petitioner's request for a remand so that he may participate in the permitting process is nonsensical since, as acknowledged in the Petition (Pet. at 10) and mentioned in the EAB Order (EAB Order at p. 2, n.1), the permit process ended when PG&E withdrew its application for the permit amendment.

Petitioner claims to satisfy "threshold procedural requirements [for EAB jurisdiction] because this Petition challenges 'changes from the draft permit to the final decision.'" (Pet. at 8.) However, BAAQMD never made a "final permit decision" on that proposed amendment because PG&E withdrew its permit amendment application before the permitting process was complete. Therefore, there is no action for the EAB to review and Petitioner cannot satisfy any "threshold procedural requirements."

Petitioner also seems to believe – without any foundation – that PG&E is operating the plant in accordance with the withdrawn, draft permit amendment.

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[9] *See* Petitioner's citations to the *withdrawn* "Application to the Bay Area Air Quality Management District for Modifications to the Authority to Construct for the Gateway Generating Station, Antioch, California." (Pet. at 10-13; Pet. Exh. 6.).

(Pet. at 10.) Petitioner's mere belief that BAAQMD amended the permit or that Gateway is operating pursuant to the proposed draft amendments, where no such agency action or evidence of operation in the purported manner exists, cannot form the basis for a Petition for Review. *See In re Tondu*, 9 E.A.D. at 724-725 (asserting an unsubstantiated opinion does not meet the petitioner's burden).

The Petition for Review also alleges that "major modifications have occurred in the construction and operation of the facility that allow it to pollute even more than the 2000-2001 BACT determinations" (Pet. at 11) and that the EAB "should remand the permit because it does not utilize Best Available Control Technology (BACT)" (Pet. at 14). Petitioner then compares 2009 BACT standards to 2001 BACT standards. Petitioner cites to the *withdrawn* permit amendment application to support an allegation that changes have been made to the facility that would require an amendment to the PSD permit. Whether or not Gateway complies with 2009 BACT standards is irrelevant because Gateway has not undergone any permitting activity that would require application of BACT since issuance of the PSD permit in 2001. Furthermore, there have been no major modifications to the facility since the issuance of the PSD permit in 2001. (R. Decl. ¶ 13.)

## V. THE EAB DOES NOT HAVE JURISDICTION TO REVIEW ALLEGED NONCOMPLIANCE

By alleging that BAAQMD "chose to quietly allow" operation of a modified facility without the necessary permits, Petitioner apparently is alleging that PG&E is operating its facility in violation of state and/or federal law. These allegations are simply untrue and unsupportable, and Petitioner has provided no evidence to support this position. As noted above, PG&E is operating the Gateway facility in full compliance with the terms and conditions of its ATC and PSD permit, as well as with all applicable federal requirements, so that there is no noncompliance issue.

Even if PG&E was in violation of one or more of its ATC or PSD permit

conditions, the EAB does not have jurisdiction to review alleged noncompliance. *See* 40 C.F.R. Part 22 (EAB jurisdiction over civil penalty cases); 40 C.F.R. Part 124 (EAB jurisdiction over permit appeals); *EAB Practice Manual*, pp. 2-4 (describing EAB jurisdiction as a reviewing body and not an independent enforcement authority.)

Lastly, Petitioner argues that "Federal Regulations require that the PSD permit be renewed every 18 months with the BACT determinations adjusted accordingly." (Pet. at 15.) The policy relied on by Petitioner (which has not been codified into regulation) refers to guidance applicable only to the process for renewing a PSD permit for a source that has not commenced construction. *See EPA Region IX Policy on PSD Permit Extensions*, p. 1 (July 6, 1988) ("This policy clarifies the subject of extensions of the 18-month commencement of construction deadline found in 40 CFR 52.21(r)(2)."). Gateway commenced construction in 2001, shortly after it received the PSD permit, thus satisfying the deadline to commence construction.[10] (R. Decl. ¶ 10.) Wholly as a matter of state law and BAAQMD rules, a District ATC expires every two years and can be renewed. *See* District Regulation 2-1-407.[11] The facility properly renewed the ATC pursuant to BAAQMD rules (R. Decl. ¶ 10), and any objection to the state law permit renewal process is not within the EAB's jurisdiction. *See In re Sutter Power Plant*, 8 E.A.D. at 688 ("[t]he Board will deny review of issues that are not governed by the PSD regulations because it lacks jurisdiction over them."); *see also Tondu*, 9 E.A.D. at 717 ("State law claims are not grounds for review.") (citing cases).

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[10] The PSD regulations define "commence construction" as

> "*Commence* as applied to construction of a major stationary source . . . means that the owner or operator has all necessary preconstruction approvals or permits and . . . [e]ntered into binding agreements or contractual obligations . . . to undertake a program of actual construction of the source. . . ."

*See* 40 C.F.R. Part 52.21(b)(9).

[11] By demonstrating that "substantial use of the authority to construct has begun" Gateway met the District's requirements for renewal of the ATC. *See* Regulation 2-1-407.3.

## VI. CONCLUSION

The Petition for Review should be summarily dismissed. Gateway is operating in accordance with the terms and conditions of the currently effective ATC and PSD permits and applicable state and federal regulations. Any challenge to the 2001 permit is clearly time-barred, and Petitioner does not have standing to bring such a challenge in any event. The PSD permit has not been amended since it was issued, and accordingly Petitioner has not been excluded from participating in any more recent permitting activity. There simply is no relief for the EAB to grant to the Petitioner, and therefore the Petition for Review should be summarily dismissed.

Accordingly, PG&E respectfully requests that the Board summarily dismiss PSD Appeal 09-02. PG&E reserves any and all rights to present further evidence and argument in the event that the EAB asserts jurisdiction over this PSD appeal.

Dated: July 2, 2009

Respectfully submitted,

PILLSBURY WINTHROP SHAW PITTMAN LLP

By _____
Attorneys for Pacific Gas and Electric Company

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## CERTIFICATE OF SERVICE

I the undersigned, hereby certify that on the 2nd day of July, 2009, service of a true and complete copy of **Intervenor Pacific Gas And Electric Company's Opposition To Petition For Review And Motion For Summary Disposition (Dismissal)** was made upon the following parties:

Alexander G. Crockett, Esq.
Assistant Counsel
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by depositing the same in the U.S. Mail.

I declare under penalty of perjury that the foregoing is true and correct.

Bertha I. Necochea

**BEFORE THE ENVIRONMENTAL APPEALS BOARD**
**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**WASHINGTON, D.C.**

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| In the Matter Of:<br>Gateway Generating Station | PSD Appeal No. 09-02 |

## DECLARATION OF GARY S. RUBENSTEIN

I, Gary S. Rubenstein, declare as follows:

1. I am a Senior Partner in the firm of Sierra Research, an air quality consulting firm based in Sacramento, California. I have over thirty-five years of experience in the field of air pollution research and control, generally, and over thirty years of experience with air permitting programs, including the federal Prevention of Significant Deterioration ("PSD") program. I am familiar with the permitting files and the air quality-related technical, regulatory and ambient air quality modeling analyses prepared for the Gateway Generating Station ("Gateway" or "facility"). In particular, the air permit application documents and supporting materials for Gateway developed subsequent to the facility's acquisition by PG&E were prepared by me or under my direct supervision. I was first retained by PG&E in connection with the facility in October 2005, when PG&E was considering the acquisition of the facility. Between October 2005 and the present, I have collected and reviewed a large number of documents related to the licensing history of the facility, including the documents described and referenced herein. I

have personal knowledge of the following facts and, if called as a witness, I could and would testify competently hereto.

2. This declaration is submitted in support of PG&E's Brief on Jurisdictional Issues and Motion for Summary Disposition (Dismissal).

3. The Bay Area Air Quality Management District ("BAAQMD" or the "District") administers the federal PSD permit program through a contractual "delegation agreement" with EPA. Attached hereto as Exhibit A is a true and correct copy of the "U.S. EPA-Bay Area AQMD Agreement for Delegation of Authority for Prevention of Significant Deterioration of Air Quality Program (40 CFR 52.21)," dated April 23, 1986, which was in effect when the District issued the Authority to Construct identified in paragraph 9 hereof, infra.

4. For various reasons related to changes in state and federal law, in 2004 EPA re-delegated limited authority to the District to administer the federal PSD permit program. Attached hereto as Exhibit D is a true and correct copy of the "U.S. EPA – Bay Area Air Quality Management District Agreement for Re-Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21," dated June 21, 2004. The facility is referred to in that document as the "Delta Power Plant."

5. In 2008, EPA again delegated authority over the federal PSD permit program to the District, expanding the scope of the previous delegation. Attached hereto as Exhibit E is a true and correct copy of the "U.S. EPA – Bay Area Air Quality Management District Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21," dated February 4, 2008.

6. The U.S. EPA-Bay Area AQMD Agreement and the District's own regulations contemplate that the District issues a single permit that functions as both a District Authority to Construct ("ATC") and a PSD permit. Attached hereto as Exhibit B is a true and correct copy of the current version of relevant District

regulations, contained in its Regulation 2, Rule 2. With respect to the matters at issue in this proceeding, the relevant District regulations are the same today as they were at the time BAAQMD issued the PSD permit in 2001.

7. On October 23, 2000, BAAQMD issued a Preliminary Determination of Compliance ("PDOC") for the facility. Attached hereto as Exhibit H is a true and correct copy of the PDOC.

8. A Final Determination of Compliance ("FDOC") for the facility was issued by the District on February 2, 2001. Attached hereto as Exhibit I is a true and correct copy of the FDOC.

9. The District issued an ATC for the Gateway facility on July 24, 2001. Attached hereto as Exhibit C is a true and correct copy of this permit. Consistent with the PSD delegation agreement, the ATC included the PSD permit.

10. On December 18, 2007, PG&E submitted to BAAQMD an application to amend certain emission limits in the PSD permit relating primarily to commissioning and start-up procedures. Attached hereto as Exhibit F is a true and correct copy of this application.

11. By letter to the District dated February 13, 2009, PG&E withdrew its permit application because PG&E determined that it could comply with the original permit conditions. Attached hereto as Exhibit G is a true and correct copy of PG&E's February 12, 2009 correspondence to the District. Since PG&E withdrew the application, the District did not amend the PSD permit.

12. To the best of my knowledge, the Gateway facility is currently operating pursuant to, and in full compliance with, all applicable permit terms and conditions.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge.

Executed at Sacramento, California on July 1, 2009.

Gary S. Rubenstein

# EXHIBIT A

United States
Environmental Protection
Agency

Regional Administrator
215 Fremont Street
San Francisco CA 94105

Region 9
Arizona, California
Hawaii, Nevada
Pacific Islands

FROM: APCO
DATE: 4/28/86
D/APCO
ADMIN
GL DIST
ENG
LEGAL
PERMIT
PERSONNEL
PLANNING
P. I. E.
TECH

EPA

April 23, 1986

Mr. Milton Feldstein
Air Pollution Control Officer
Bay Area Air Quality
Management District
939 Ellis Street
San Francisco, CA 94109

Dear Mr. Feldstein:

I am pleased to return to you a signed copy of the delegation agreement for the Prevention of Significant Deterioration program. Please note that the delegation is effective on the date of my signature.

We have discussed with your staff the procedures for transferring PSD review to the District, including the disposition of authority for each PSD project currently under review. These procedures are also enclosed with this letter.

BAAQMD assumption of this key air pollution control program will enable the District to make the environmental decisions that are most properly the subject of local concern and control. I wish to reiterate EPA's firm commitment to provide any necessary technical assistance you may request during program implementation.

Sincerely,

John Wise

for JUDITH E. AYRES
Regional Administrator

Enclosure

cc: Ray Menebroker, ARB

U.S. EPA-BAY AREA AQMD AGREEMENT

FOR DELEGATION OF AUTHORITY FOR PREVENTION OF

SIGNIFICANT DETERIORATION OF AIR QUALITY (40 CFR 52.21)

The undersigned, on behalf of the Bay Area Air Quality Management District (BAAQMD) and the United States Environmental Protection Agency (U.S. EPA), hereby agree to the delegation of authority of the administrative and enforcement elements of the stationary source review provisions of 40 CFR 52.21, Prevention of Significant Deterioration (PSD) from the U.S. EPA to the BAAQMD, subject to the terms and conditions below. EPA has determined that the PSD portion of the District Rule 2 of Regulation 2 (adopted March 7, 1984 with minor revisions adopted subsequently) generally meets the requirements of 52.21; therefore, District permits issued in accordance with the provisions of Rule 2 of Regulation 2 will be deemed to meet federal PSD permit requirements pursuant to the provisions of this delegation agreement. This delegation is executed pursuant to 40 CFR 52.21(u), Delegation of Authority.

Permits

1. District permits issued pursuant to this agreement must meet the requirements of District Rule 2 of Regulation 2

2. EPA has revised portions of its stack height regulation. EPA reserves permitting authority for PSD sources with stack heights greater than 65 meters or sources which use a dispersion technique as defined by EPA, unless the District permits would comply with EPA's final stack height regulation (50 FR 44878 July 8, 1985).

3. EPA reserves authority for performing the review of the visibility impacts of new or modified major stationary sources that may adversely impact visibility in mandatory Class I areas unless the District permits would comply with EPA's final regulations regarding visibility review (50 FR 28544, July 12, 1985).

4. It is the understanding of the parties that, consistent with the provisions of Rule 2 of Regulation 2 and pursuant to Section 41700 of the California Health and Safety Code, actual emission decreases are creditable only to the extent that the reductions have approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

5. The District will request EPA guidance on any matter involving the interpretation of Sections 160-169 of the Clean

Air Act or 40 CFR 52.21 to the extent that implementation, review, administration or enforcement of these sections has not been covered by determinations or guidance sent to the District.

6. Pursuant to its authority under the Clean Air Act and upon reasonable notice, EPA may review the permits issued by the District under this agreement to insure that the District's implementation of Rule 2 of Regulation 2 is consistent with the contemporaneous time frame and actual emissions baseline requirements of federal regulations (40 CFR 52.21(b)(3)).

7. Pursuant to provisions of Section 7(a) of the Endangered Species Act of 1973 (16 U.S.C. 1536(a)), EPA may not delegate and hereby retains its responsibilities to ensure that PSD permitting actions by the District are not likely to jeopardize the continued existence of endangered or threatened species, or adversely modify their critical habitats.

8. District permits issued pursuant to this agreement which meet the requirements of 40 CFR 52.21 will be considered valid by EPA. The determination of compliance or noncompliance with 40 CFR 52.21 shall be made by EPA. The District shall issue a permit to applicants using District regulations and authority.

General Conditions

1. This delegation may be amended at any time by the formal formal written agreement of both the BAAQMD and the U.S. EPA including amendments to add, change, or remove conditions or terms of this agreement.

2. If the District adopts revisions to Rule 2 of Regulation 2 EPA may take steps to revoke the delegation agreement in whole or in part pursuant to condition 3 below or the parties may amend the agreement pursuant to condition 1 above. Any amendments to Rule 2 of Regulation 2 which are adopted by the District, shall not be applied under this agreement until this agreement is amended so to provide.

3. If the U.S. EPA determines that the BAAQMD is not implementing the PSD program in accordance with the terms and conditions of this agreement, this delegation, after consultation with the BAAQMD, may be revoked in whole or in part. Any such revocation shall be effective as of the date specifed in a Notice of Revocation to the BAAQMD.

4. This delegation of authority shall terminate upon the date EPA promulgates final approval or disapproval of District Rule 2 of Regulation 2.

5. This delegation of authority is effective upon the date of the signatures of both parties to this agreement.

Date: April 7, 1986

Bay Area Air Quality
Management District

Date: 4.23.86

John Wise
U.S. Environmental
Protection Agency

Procedures for Transferring Review of PSD Permits from EPA Region 9 to the BAAQMD

A. EPA currently has three active PSD permit applications for sources in the Bay Area District:

1) West County Agency

2) PG&E Station T

3) Bay Area Resource Recovery Facility (Combustion Engineering)

Both the West County Agency and PG&E Station T have been released for public comment. EPA will process these permits and issue final permits for these projects. The application for the Bay Area Resource Recovery Facility is not yet complete; EPA will transfer permit review responsibility to the District.

B. In order to assist EPA in carrying out its non-delegable responsibilities pursuant to the Endangered Species Act, EPA requests that the District:

1) Notify potential applicants of the potential need for consultation between EPA and the Fish and Wildlife Service (FWS) if an endangered species may be affected by the project. EPA's data sheet (copy enclosed) may be used for this purpose.

2) Notify EPA by letter, and FWS by copy of the letter, when a PSD application has been received.

3) Cooperate with EPA and FWS to obtain necessary data from the applicant for the purpose of carrying out Section 7 responsibilities.

4) Refrain from issuing a final PSD permit unless the FWS has determined that the proposed project will not adversely affect any endangered species.

C. EPA is currently developing national policy regarding modification and extension of PSD permits. When this policy is released to the public, the District would be expected to use this policy (or a more stringent approach) as the basis for decisions on PSD permit modifications and extensions.

EPA Region IX
New Source Section
Policy No.: 1-86

# PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT APPLICANT REQUIREMENTS

## UNDER THE

## ENDANGERED SPECIES ACT

Section 7 of the Endangered Species Act (PL 97-304), as amended in 1982, requires all federal agencies, in consultation with the Fish and Wildlife Service (FWS), to insure that their actions are not likely to jeopardize the continued existence of endangered or threatened species, or adversely modify their critical habitats.

If the issuance of a permit for construction/modification will result in an adverse impact on a listed species, the EPA must initiate formal consultation with the FWS regarding the proposed action. Therefore, at an early stage in the PSD application process, the applicant should submit a request to the FWS (see address below) for information on whether any listed or proposed species or critical habitat or proposed critical habitat may be present in the area affected by the applicant's proposed action. Please provide EPA Region 9 with a copy of all correspondence concerning Endangered Species Act compliance.

When a list of endangered or threatened species present within the project area has been provided by the FWS, the applicant has 180 days to complete a biological assessment. The biological assessment must be submitted to the FWS by the EPA along with the request for formal consultation. The FWS then has 60-90 days to issue a biological opinion based on the information submitted.

The biological assessment should identify any listed or proposed species or critical habitat or proposed critical habitat that is in the action area and should describe the effects that the action may have on such species and critical habitat. The assessment also shall include an analysis of cumulative effects. The FWS will provide recommendations for necessary studies, surveys and information to include in the assessment.

FISH AND WILDLIFE SERVICE CONTACTS:

California:

All counties north of Santa Barbara, Ventura, Los Angeles, and San Bernadino:
Endangered Species Office
2800 Cottage Way, Rm. E-1823
Sacramento, CA 95814
(916)978-4866

Southern portion of state not covered by Sacramento office:
Ecological Services Field Office
24000 Avila Road
Laguna Niguel, CA 92677
(714)643-4270

Pacific Area:

Pacific Islands Administrator
ATTN: Endangered Species
300 Ala Moana Blvd.
Rm. 6307, P.O. Box 50167
Honolulu, HI 96850
(808)546-7530

EPA CONTACTS:

Key Policy Contact: Anita Tenley (415)974-8240
Section Chief: Wayne A. Blackard

# EXHIBIT B

# REGULATION 2
# PERMITS
# RULE 2
# NEW SOURCE REVIEW

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# REGULATION 2
# PERMITS
# RULE 2
# NEW SOURCE REVIEW

(Readopted and Renumbered July 17, 1991)

**2-2-100 GENERAL**

**2-2-101 Description:** This Rule shall apply to all new and modified sources which are subject to the requirements of Regulation 2-1-301. The purpose of this Rule is to provide for the review of new and modified sources and provide mechanisms, including the use of Best Available Control Technology (BACT), Best Available Control Technology for Toxics (TBACT), and emission offsets, by which authorities to construct such sources may be granted. This rule implements the no net increase requirements of Section 40919 (a)(2) of the Health and Safety Code as demonstrated by the requirements of Section 2-2-316. The New Source Review provisions of 40 CFR 51.165 and the Prevention of Significant Deterioration provisions of 40 CFR 51.166 are hereby incorporated by reference.

*(Amended 6/15/94; 10/7/98; 5/17/00)*

**2-2-110 Deleted October 7, 1998**

**2-2-111 Exemption, PSD Monitoring:** The APCO may exempt an applicant from the requirements of subsection 2-2-414.3 provided that the applicant demonstrates by modeling to the satisfaction of the APCO that the cumulative emission increase minus the emission reduction credits from the new or modified facility would cause air quality impacts less than the following, or may exempt an applicant from the requirements of subsection 2-2-414.3 if the existing ambient air quality concentrations in the impact area are no greater than the following:

| | (micrograms per cubic meter, $\mu g/m^3$) |
|---|---|
| Carbon monoxide: 8-hr average | 575 |
| $PM_{10}$: 24-hr average | 10 |
| Sulfur dioxide: 24-hr average | 13 |
| Lead: 3-month average | 0.1 |
| Mercury: 24-hr average | 0.25 |
| Beryllium: 24-hr average | 0.0001 |
| Fluorides: 24-hr average | 0.25 |
| Vinyl chlorides: 24-hr average | 15 |
| Total reduced sulfur: 1-hr average | 10 |
| Hydrogen sulfide: 1-hr average | 0.2 |
| Reduced sulfur compounds: 1-hr average | 10 |
| Nitrogen dioxide: annual average | 14 |

*(Amended June 15, 1994)*

**2-2-112 Exemption, Secondary Emissions From Abatement:** The BACT requirements of Section 2-2-301 shall not apply to emissions of secondary pollutants which are the direct result of the use of an abatement device or emission reduction technique which complies with the BACT or BARCT requirements for control of another pollutant. However, the APCO shall require the use of Reasonably Available Control Technology (RACT) for control of these secondary pollutants. The Air Pollution Control Officer shall determine which pollutants are primary and which are secondary for the equipment being evaluated.

*(Amended 6/15/94; 10/7/98)*

**2-2-113 Deleted June 15, 1994**

**2-2-114 Exemption, MACT Requirement:** The MACT requirement of Section 2-2-317 shall not apply to the following:

114.1 Any source, where the combined increase in potential to emit from all related sources in a proposed construction or modification is less than 10 tons per year of any HAP and less than 25 tons per year of any combination of HAPs.

114.2 Any source that has been specifically regulated under a standard promulgated pursuant to Sections 112(d), 112(h), or 112(j) of the federal Clean Air Act prior to the date that the APCO has issued an Authority to Construct.

114.3 Any source that has been specifically exempted from regulation under a standard issued pursuant to Sections 112(d), 112(h), or 112(j) of the federal Clean Air Act.

114.4 Any Electric Utility Steam Generating Unit as defined in 40 CFR 63.41, unless and until such time as these units are added to the source category list pursuant to Section 112(c)(5) of the federal Clean Air Act.

114.5 Any Research and Development Activities as defined in 40 CFR 63.41.

114.6 Any source that is within a source category that has been deleted from the source category list pursuant to Section 112(c)(9) of the federal Clean Air Act.

*(Adopted May 17, 2000)*

## 2-2-200 DEFINITIONS

**2-2-201** **Emission Reduction Credit:** Except as provided by subsection 2-2-201.3 an emission reduction, calculated in accordance with Section 2-2-605, which exceeds the emission reductions required by measures in the current Clean Air Plan approved by the BAAQMD or required by federal, state, or District laws, rules, and regulations. To qualify as an emission reduction credit, the emission reduction must be in excess of the reductions achieved by, or achievable by, the source using Reasonably Available Control Technology (RACT), and must also be real, permanent, quantifiable, and enforceable.

201.1 Unless calculated in accordance with the procedures of Section 2-2-605, that portion of an NSR emission cap, which was part of an APCO approved alternative baseline, shall not qualify as an emission reduction credit.

201.2 All emission reduction credits shall be enforceable by permit conditions in the authority to construct and permit to operate, except that, in the case of source closures where no permit is required for the source being shut down, the emission reduction credit shall be enforceable through appropriate contractual provisions in a legally binding and irrevocable written agreement in which provisions will be made expressly for the benefit of the District.

201.3 For the purpose of complying with the PSD requirements of Sections 2-2-111, 304, 305, 306, 308 of this Rule and 40 CFR 51.166, emission reduction credits shall not be adjusted for reductions required by measures in the current Clean Air Plan approved by the BAAQMD which exceed the reductions required by use of Reasonably Available Control Technology (RACT).

The permanence of a closure shall be identified in a letter from the source and/or in a Banking Certificate.

*(Amended June 15, 1994)*

**2-2-202** **Baseline Area, PSD:** All intrastate Air Quality Control Regions, as defined in 40 CFR 52.21, and every part thereof, designated as attainment or unclassifiable under 107(d)(1)(D) or (E) of the Clean Air Act in which a source establishing a baseline date would construct or would have an air quality impact equal to or greater than 1 µg/m3 (annual average) of the pollutant for which the baseline date is established.

**2-2-203** **Baseline Concentration, PSD:** The ambient concentration level which exists in the baseline area on the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established. The baseline concentration shall include the actual emissions representative of sources in existence on the applicable baseline date.

*(Amended October 7, 1998)*

**2-2-204** **Baseline Date, PSD:** The earliest date after December 20, 1977, for sulfur dioxide and $PM_{10}$, or after February 8, 1988, for nitrogen dioxide, for each baseline area on which the first complete application under Section 2-2-304 is submitted or was

submitted to EPA under 40 CFR 52.21. The baseline date is established for each pollutant for which PSD increments have been established.

**2-2-205** **Baseline Period, PSD:** The period against which a change in emissions is to be measured.

**2-2-206** **Best Available Control Technology (BACT):** For any new or modified source, except cargo carriers, the more stringent of:

206.1 The most effective emission control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

206.2 The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

206.3 Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

206.4 The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations.

The APCO shall publish and periodically update a BACT/TBACT Workbook specifying the requirements for commonly permitted sources. BACT will be determined for a source by using the workbook as a guidance document or, on a case-by-case basis, using the most stringent definition of this Section 2-2-206.

*(Amended October 7, 1998)*

**2-2-207** **California Coastal Waters:** That area between the California-Oregon border at the Pacific Ocean and ending at the California-Mexico border at the Pacific Ocean:

| | |
|---|---|
| thence to 42.0°N | 125.5°W |
| thence to 41.0°N | 125.5°W |
| thence to 40.0°N | 125.5°W |
| thence to 39.0°N | 125.5°W |
| thence to 38.0°N | 124.0°N |
| thence to 37.0°N | 123.5°W |
| thence to 36.0°N | 122.5°W |
| thence to 35.0°N | 121.5°W |
| thence to 34.0°N | 120.5°W |
| thence to 33.0°N | 119.5°W |
| thence to 32.5°N | 118.5°W |

**2-2-208** **CEQA:** The California Environmental Quality Act, Public Resources Code, Section 21000, et seq., and the CEQA guidelines, Title 14, California Code of Regulations, Section 15000, et seq.

*(Amended May 17, 2000)*

**2-2-209** **Class I Areas, PSD:** Point Reyes National Seashore and any other Class I Area under Part C of the Clean Air Act. All other areas in the District are Class II Areas.

**2-2-210** **Deleted May 17, 2000**

**2-2-211** **Contiguous Properties:** Two or more parcels of land with a common boundary or separated solely by a public roadway or other public right-of-way.

**2-2-212** **Cumulative Increase:** The aggregate sum of all increases in emissions of any given pollutant from a facility pursuant to authorities to construct or permits to operate issued after April 5, 1991 (unless a PSD Baseline Date is applicable), excluding emissions from a source which has lost its permit exemption per Regulation 2-1-424.

*(Amended 6/15/94; 10/7/98)*

**2-2-213** **EIR:** Environmental Impact Report, as defined in Section 21061 of the Public Resources Code.

**2-2-214** **Emission Offsets:** Emission reduction credits which are used to mitigate cumulative increases of emissions. Emission offsets are emission reduction credits, from the District Emissions Bank, approved in accordance with Regulation 2, Rule 4; emission reduction credits from adjacent Districts, provided the applicant demonstrates that the requirements of Clean Air Act Section 173(c)(1) (42 U.S.C. Section 7503(c)(1))

and Health and Safety Code Section 40709.6 have been met or do not apply, or onsite contemporaneous emission reduction credits occurring after the submittal of an application for a new or modified source but prior to the issuance of the permit to operate any such source, calculated in accordance with Section 2-2-605. Notwithstanding any existing permit conditions, that portion of an NSR emission cap, which was based on an APCO approved alternative baseline, may not be used as a source of offsets unless the proposed reduction is calculated in accordance with procedures specified in Section 2-2-605.

*(Amended 6/15/94; 5/17/00)*

**2-2-215** **Facility:** Any property, building, structure or installation (or any aggregation of facilities) located on one or more contiguous or adjacent properties and under common ownership or control of the same person that emits or may emit any air pollutant and is considered a single major industrial grouping (identified by the first two-digits of the applicable code in The Standard Industrial Classification Manual). In addition, facilities which include cargo loading or unloading from cargo carriers other than motor vehicles shall include the cargo carriers as part of the source which receives or loads the cargo. Accordingly, all emissions from such carriers while operating in the District, or within California Coastal Waters adjacent to the District, shall be included as part of the source emissions.

215.1 For determining the cumulative increase at a facility subject to the offset requirements of Sections 2-2-302 and 303, related sources on a single property or contiguous properties, even though under different ownership, or related sources on non-contiguous properties under the same ownership shall be considered one facility. Related sources are those sources where the operation of one is dependent upon or affects the operation of the other.

215.2 Notwithstanding the definition in Section 2-2-215 above, the emissions related to cargo carriers shall not be included when determining applicability of the requirements of Sections 2-2-304, 2-2-308, 2-6-301, and 2-6-310.

215.3 For determining the cumulative increase at a facility subject to the offset requirements of Sections 2-2-302 and 303, facilities under the same ownership or entitlement to use that are located within a distance of three miles, property line to property line, shall be considered one facility if the facilities have the same first two digits in their Standard Industrial Classification codes, as determined from The Standard Industrial Classification Manual.

*(Amended November 3, 1993)*

**2-2-216** **Feasible:** Capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors, not in conflict with the mandated responsibilities and duties of the District.

**2-2-217** **Federal Land Manager:** With respect to any lands in the United States, the Secretary of the department with authority over such lands.

**2-2-218** **Federally Enforceable:** All limitations and conditions that are enforceable by the Administrator of the U. S. EPA, including requirements developed pursuant to 40 CFR Parts 60 (NSPS), 61 (NESHAPS), 63 (HAP), 70 (State Operating Permit Programs) and 72 (Permits Regulation, Acid Rain), requirements contained in the State Implementation Plan (SIP) that are applicable to the District, any District permit requirements established pursuant to 40 CFR 52.21 (PSD) or District regulations approved pursuant to 40 CFR Part 51, Subpart I (NSR), and any operating permits issued under an EPA-approved program that is a part of the SIP and expressly requires adherence to any permit issued under such program.

*(Amended November 3, 1993).*

**2-2-219** **Impact Area:** The area in which a new or modified facility would have a significant air quality impact.

**2-2-220** **Deleted May 17, 2000**

**2-2-221** **Major Modification of a Major Facility:** Any modification, as defined in Regulation 2-1-234, at an existing major facility that the APCO determines will cause an increase of the facility's emissions by the following amounts or more:

POC: 40 tons per year

| | |
|---|---|
| NOx: | 40 tons per year |
| $SO_2$: | 40 tons per year |
| $PM_{10}$: | 15 tons per year |
| CO: | 100 tons per year |

*(Amended June 15, 1994)*

**2-2-222** **Modeling, PSD:** Estimates of ambient concentrations of pollutants based on applicable air quality models, data bases and other requirements acceptable to the APCO. For modeling required by Sections 2-2-304 through 308 and 414, the air quality models, data bases and other requirements shall also be in accordance with the "Guideline on Air Quality Models", EPA-450/2-78-027R, July 1986 or as revised). Where an air quality impact model specified in the "Guideline on Air Quality Models" is inappropriate, the model may be modified or another model substituted provided that written approval from the Administrator of the EPA is obtained and the application is submitted for public comment in accordance with Section 2-2-405. Methods such as those outlined in the "Workbook for the Comparison of Air Quality Models", April 1977 (or as revised) shall be used to determine the comparability of air quality models. For modeling compliance with air quality standards, other than federal ambient air quality standards or federal PSD increments, applicable models must be approved by the APCO.

**2-2-223** **Deleted May 17, 2000**

**2-2-224** **Net Air Quality Benefit:** A net improvement of air quality as determined by the APCO resulting from emission reduction credits impacting the same general area affected by the new or modified source and which will be consistent with reasonable further progress towards the attainment of the applicable air quality standard.

*(Amended June 15, 1994)*

**2-2-225** **Deleted May 17, 2000**

**2-2-226** **Deleted October 7, 1998**

**2-2-227** **Deleted October 7, 1998**

**2-2-228** **Deleted October 7, 1998**

**2-2-229** **Deleted October 7, 1998**

**2-2-230** **Deleted October 7, 1998**

**2-2-231** **Point of Maximum Ground Level Impact:** The ground level geographic location where the projected air pollution concentrations for a given pollutant resulting from the new or modified facility emissions together with the background pollutant concentration for that given pollutant results in the maximum ground level pollutant concentration. The background pollutant concentration means the ambient concentration level resulting from the actual emissions of sources in existence and the projected ambient concentration levels for sources already permitted but not yet in operation. If the general public is effectively excluded from the property on which the point of maximum ground level impact is located, and the property is owned or controlled by the owner of the new or modified facility, such property shall not be considered as the point of maximum ground level impact.

**2-2-232** **Prevention of Significant Deterioration (PSD) Increments:** In areas designated as Class I, II or III, increases in pollutant concentration over the baseline concentration shall be limited to the following:

## MAXIMUM ALLOWABLE INCREASE

(micrograms per cubic meter, $\mu g/m^3$)

**CLASS I**

| POLLUTANT | |
|---|---|
| Particulate Matter: | |
| $PM_{10}$ Annual arithmetic mean | 4 |
| $PM_{10}$ 24-hr maximum | 8 |
| Sulfur Dioxide: | |
| Annual arithmetic mean | 2 |
| 24-hr maximum | 5 |
| 3-hr maximum | 25 |
| Nitrogen Dioxide: | |

| | |
|---|---|
| Annual arithmetic mean | 2.5 |

**CLASS II**

| | |
|---|---|
| Particulate Matter: | |
| $PM_{10}$ Annual arithmetic mean | 17 |
| $PM_{10}$ 24-hr maximum | 30 |
| Sulfur Dioxide: | |
| Annual arithmetic mean | 20 |
| 24-hr maximum | 91 |
| 3-hr maximum | 512 |
| Nitrogen Dioxide: | |
| Annual arithmetic mean | 25 |

**CLASS III**

| | |
|---|---|
| Particulate Matter: | |
| $PM_{10}$ Annual arithmetic mean | 34 |
| $PM_{10}$ 24-hr maximum | 60 |
| Sulfur Dioxide: | |
| Annual arithmetic mean | 40 |
| 24-hr maximum | 182 |
| 3-hr maximum | 700 |
| Nitrogen Dioxide: | |
| Annual arithmetic mean | 50 |

For any period other than an annual period, the applicable increase may be exceeded during one such period per year at any one location.

*(Amended June 15, 1994)*

**2-2-233** **Significant Air Quality Impacts, PSD:** Ambient air concentrations, resulting from new or modified facility emissions, that exceed any of the following levels:

**SIGNIFICANT AIR QUALITY IMPACTS**
(MICROGRAMS PER CUBIC METER, $\mu G/M^3$)

| POLLUTANT | |
|---|---|
| Particulate Matter: | |
| $PM_{10}$, Annual arithmetic mean | 1.0 |
| $PM_{10}$, 24-hr maximum | 5 |
| Sulfur Dioxide: | |
| Annual arithmetic mean | 1.0 |
| 24-hr maximum | 5 |
| 3-hr maximum | 25 |
| Nitrogen Dioxide: | |
| Annual arithmetic mean | 1.0 |
| 1-hr maximum | 19 |
| Carbon Monoxide: | |
| 8-hr maximum | 500 |
| 1-hr maximum | 2000 |

*(Amended June 15, 1994)*

**2-2-234** **Source:** Any article, machine, equipment, operation, contrivance or related groupings of such which may produce and/or emit air pollutants.

**2-2-235** **Year, Month, and Day:** Unless otherwise defined, a year shall be any rolling 365 consecutive day period, a month shall be any rolling 31 consecutive day period and a day shall be any rolling 24 consecutive hour period.

**2-2-236** **Hazardous Air Pollutant (HAP):** Any pollutant that is listed pursuant to Section 112(b) of the federal Clean Air Act.

*(Adopted 11/3/93; Amended 5/17/00)*

**2-2-237** **Major Facility Review (MFR):** Plantwide review of sources, emissions and regulatory requirements at facilities including, but not limited to, major facilities, phase II acid rain facilities, subject solid waste incinerator facilities, designated facilities, and synthetic minor facility candidates, which are potentially subject to the

permitting requirements of Regulation 2, Rule 6, and Title V of the federal Clean Air Act.

*(Adopted November 3, 1993)*

**2-2-238** **Deleted May 17, 2000**

**2-2-239** **Deleted May 17, 2000**

**2-2-240** **Best Available Retrofit Control Technology (BARCT):** An emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy and economic impacts by each class or category of source and has been adopted or proposed to be adopted as part of the current Clean Air Plan required by the California Clean Air Act of 1988.

*(Adopted June 15, 1994)*

**2-2-241** **Deleted May 17, 2000**

**2-2-242** **Contemporaneous:** The five year period of time immediately prior to the date of application for an authority to construct or permit to operate.

*(Adopted June 15, 1994)*

**2-2-243** **Reasonably Available Control Technology (RACT):** For sources which are to continue operating, RACT is the lowest emission limit that can be achieved by the specific source by the application of control technology taking into account technological feasibility and cost-effectiveness, and the specific design features or extent of necessary modifications to the source. For sources which are or will be shut-down, RACT is the lowest emission limit that can be achieved by the application of control technology to similar, but not necessarily identical categories of sources, taking into account technological feasibility and cost-effectiveness of the application of the control technology to the category of sources only and not to the shut-down source.

*(Adopted June 15, 1994)*

**2-2-244** **Best Available Control Technology for Toxics (TBACT):** For any new or modified source, except cargo carriers, the most stringent of the following emission controls, provided that under no circumstances shall the controls be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules, regulations or requirements:

244.1 The most effective emission control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

244.2 The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

244.3 Any control device or technique or any emission limitation that the APCO has determined to be technologically feasible for the type of equipment comprising such a source, while taking into consideration the cost of achieving emission reductions, any non-air quality health and environmental impacts, and energy requirements; or

244.4 The most stringent emission control for a source type or category for which a Maximum Achievable Control Technology (MACT) standard has been proposed, or for which the CARB has developed an Airborne Toxic Control Measure (ATCM).

*(Adopted 5/17/00; Amended 6/15/05)*

**2-2-245** **Fully Offset:** An emission cap or emission rate contained in a permit condition is fully offset if offsets were provided for the entire amount of the emission cap or emission rate, and the entire amount of offsets is composed of contemporaneous emission reductions or banked emission reduction credits.

*(Adopted May 17, 2000)*

**2-2-246** **Adjustment to Emission Reductions for Federal Purposes**: An adjustment made, for purposes of the equivalence demonstration in 2-2-423, to an emission reduction, due to changes in federal requirements between issuance of a banking certificate and its use. The adjustment is made as if the source providing the offsets were in operation, at the original baseline levels, on the date of credit use.

*(Adopted May 17, 2000)*

**2-2-300 STANDARDS**

**2-2-301** **Best Available Control Technology Requirement:** An applicant for an authority to construct or a permit to operate shall apply BACT to any new or modified source:

301.1 Which results in an emission from a new source or an increase in emissions from a modified source and which has the potential to emit 10.0 pounds or more per highest day of precursor organic compounds (POC), non-precursor organic compounds (NPOC), nitrogen oxides (NOx), sulfur dioxide ($SO_2$), $PM_{10}$ or carbon monoxide (CO). BACT shall be applied for any of the above pollutants which meets both criteria.

*(Amended 6/15/94; 10/7/98; 5/17/00)*

**2-2-302** **Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR:** Except as provided by Sections 2-2-313 or 421, before the APCO may issue an authority to construct or a permit to operate for a new or modified source at a facility which emits 35 tons per year or more or will be permitted to emit 35 tons per year or more, on a pollutant specific basis, of precursor organic compounds or nitrogen oxides, federally enforceable emission offsets shall be provided, for the emission from the new or modified source and any pre-existing cumulative increase, minus any onsite contemporaneous emission reduction credits determined in accordance with Section 2-2-605, at a 1.15 to 1.0 ratio; additionally, the applicant must reimburse the District Small Facility Banking Account for any unreimbursed offsets previously provided by the District, at a 1.0 to 1.0 ratio. Before the APCO may issue an authority to construct or a permit to operate for a new or modified source at a facility which emits or will be permitted to emit more than 10 tons per year but less than 35 tons per year, on a pollutant specific basis, of precursor organic compounds or nitrogen oxides, emission offsets shall be provided, by the District (or by the applicant, if the Small Facility Banking account has been exhausted) at a 1.0 to 1.0 ratio for the emission from the new or modified source and any pre-existing cumulative increase, minus any onsite contemporaneous emission reduction credits determined in accordance with Section 2-2-605, from the Small Facility Banking account in the District's Emissions Bank in accordance with the provisions of Regulations 2-4-414. The APCO shall determine the total facility emissions, on a pollutant specific basis, by adding the emissions from the proposed new or modified source(s) to the most recent District Emissions Inventory, adjusted for any errors and adjusted upward for any permitted levels of emissions not currently being emitted.

302.1 Deleted May 17, 2000

302.2 Emission reduction credits of precursor organic compounds may be used to offset increased emissions of nitrogen oxides at the offset ratio specified above in Section 2-2-302, provided that the PSD requirements of Section 2-2-304, if applicable, are met.

302.3 Reimbursement of the small facility bank may be provided by adjusting the cumulative increase calculated for the application for which small facility bank credits were originally provided. An adjustment may be made under the following circumstances: the applicant accepts an enforceable permit condition limiting emissions to a lower level than approved in the permit in question, or the applicant surrenders the permit.

*(Amended 11/20/91; 6/15/94; 10/7/98; 5/17/00; 12/21/04)*

**2-2-303** **Offset Requirement, $PM_{10}$ and Sulfur Dioxide, NSR:** Except as provided by Section 2-2-421, before the APCO may issue an authority to construct or a permit to operate for a new or modified source, of PM10 or sulfur dioxide located at a Major Facility, which will result in a cumulative increase minus any contemporaneous emission reduction credits at the facility, for that pollutant, in excess of 1.0 ton per year since April 5, 1991, emission offsets shall be provided, for the emission from the new or modified source and any pre-existing cumulative increase, minus any onsite contemporaneous emission reduction credits determined in accordance with Section 2-2-605, at a 1.0:1.0 ratio or at a ratio, approved by the APCO, in accordance with subsection 2-2-303.1.

303.1 Emission reduction credits of nitrogen oxides and/or sulfur dioxide may be used to offset increased emissions of $PM_{10}$ at offset ratios determined by the APCO to result in a net air quality benefit. This determination shall be made

after a case-by-case analysis that includes adequate modeling, public notice and opportunity for public comment, and EPA concurrence.

A facility which emits less than 100 tons of any pollutant, subject to this section, may voluntarily provide emission offsets for all, or any portion, of their cumulative increase, at the ratio required above.

*(Amended 11/20/91; 6/15/94; 5/17/00)*

**2-2-304** **PSD Requirement:** In accordance with the Prevention of Significant Deterioration provisions of 40 CFR 51.166 of the Code of Federal Regulations, the APCO shall not issue an authority to construct or a permit to operate to:

304.1 A new major facility which will emit 100 tons per year or more, if, it is one of the twenty eight (28) PSD source categories listed in Section 169(1) of the federal Clean Air Act, or 250 tons per year or more for an unlisted category, of any pollutant subject to regulation under the federal Clean Air Act unless the applicant demonstrates by modeling in accordance with Section 2-2-414 to the satisfaction of the APCO that such emissions will not interfere with the attainment or maintenance of the applicable sulfur dioxide or nitrogen dioxide NAAQS at the point of maximum ground level impact and will not cause an exceedance of a sulfur dioxide or a nitrogen dioxide PSD increment.

304.2 A major modification of a major facility if the cumulative increase, from the PSD Baseline Date, minus the contemporaneous emission reduction credits at the facility are in excess of 40 tons per year of sulfur dioxide or nitrogen oxides unless the applicant demonstrates by modeling in accordance with Section 2-2-414 to the satisfaction of the APCO that such emissions will not interfere with the attainment or maintenance of the applicable sulfur dioxide or nitrogen dioxide NAAQS at the point of maximum ground level impact and will not cause an exceedance of a sulfur dioxide or a nitrogen dioxide PSD increment.

304.3 A major modification of a major facility if the cumulative increase, from the PSD Baseline Date, minus the contemporaneous emission reduction credits at the facility are in excess of 15 tons per year of $PM_{10}$ unless the applicant demonstrates by modeling in accordance with Section 2-2-414 to the satisfaction of the APCO that such emission will not interfere with the attainment or maintenance of the $PM_{10}$ federal ambient air quality standard at the point of maximum ground level impact and will not cause an exceedance of a $PM_{10}$ PSD increment.

304.4 A major modification of a major facility if the cumulative increase, from the PSD Baseline Date, minus the contemporaneous emission reduction credits at the facility are in excess of 0.6 tons per year of lead unless the applicant demonstrates by modeling in accordance with Section 2-2-414 to the satisfaction of the APCO that such emission will not interfere with the attainment or maintenance of the lead federal ambient air quality standard at the point of maximum ground level impact and will not cause an exceedance of a lead PSD increment.

*(Amended 6/15/94; 5/17/00)*

**2-2-305** **Carbon Monoxide Modeling Requirement, PSD:** In accordance with the Prevention of Significant Deterioration provisions of 40 CFR 51.166 of the Code of Federal Regulations, the APCO shall not issue an authority to construct or a permit to operate for:

305.1 A new major facility which will emit 100 tons per year or more, if it is one of the twenty eight (28) PSD source categories listed in Section 169(1) of the federal Clean Air Act, or 250 tons per year or more for an unlisted category, of any pollutant subject to regulation under the federal Clean Air Act, unless the applicant demonstrates by modeling in accordance with Section 2-2-414, to the satisfaction of the APCO, that the net air quality impact of the cumulative increase of emissions of CO from the new or modified facility and all contemporaneous emission reduction credits to be provided by the applicant will not interfere with the attainment or maintenance of the CO NAAQS in the District or any contiguous air basin, or

1.1 The cumulative increase minus the contemporaneous emission reduction credits from the facility are less than or equal to zero.

305.2 A major modification of a major facility with an increase of 100 tons per year or more of carbon monoxide, unless the applicant demonstrates by modeling in accordance with Section 2-2-414, to the satisfaction of the APCO, that the net air quality impact of the cumulative increase of emissions of CO from the new or modified facility and all contemporaneous emission reduction credits to be provided by the applicant will not interfere with the attainment or maintenance of the CO NAAQS in the District or any contiguous air basin, or

2.1 The cumulative increase minus the contemporaneous emission reduction credits from the facility are less than or equal to zero.

*(Amended 6/15/94; 5/17/00)*

**2-2-306** **Non-Criteria Pollutant Analysis, PSD:** In accordance with the Prevention of Significant Deterioration provisions of 40 CFR 51.166 of the Code of Federal Regulations, unless the applicant has performed all analysis required by Sections 2-2-414 and 417 for the applicable pollutants, the APCO shall not issue an authority to construct or a permit to operate to a new or modified facility if the new or modified facility will emit greater than 100 tons per year of carbon monoxide, $PM_{10}$, sulfur dioxide, precursor organic compounds or nitrogen oxides, and the increase in emissions due to the permit application, minus the onsite contemporaneous emission reduction credits associated with the permit application are in excess of the annual average amounts specified below:

| | ANNUAL AVERAGE | | DAILY | |
|---|---|---|---|---|
| | **kg/yr** | **(ton/yr)** | **g/day** | **(lb/day)** |
| Lead | 530 | (0.6) | 1450 | (3.2) |
| Asbestos | 6 | (0.007) | 17 | (0.04) |
| Beryllium | 0.3 | (0.0004) | 0.9 | (0.002) |
| Mercury | 88 | (0.1) | 240 | (0.5) |
| Fluorides | 2720 | (3) | 7450 | (16) |
| Sulfuric Acid Mist | 6350 | (7) | 17400 | (38) |
| Hydrogen Sulfide | 9050 | (10) | 24800 | (55) |
| Total Reduced Sulfur | 9050 | (10) | 24800 | (55) |
| Reduced Sulfur Compounds | 9050 | (10) | 24800 | (55) |

*(Amended 6/15/94; 5/17/00)*

**2-2-307** **Denial, Failure of all Facilities to be in Compliance:** The APCO shall deny an authority to construct for a new major facility or a major modification of an existing major facility unless the applicant provides a list, certified under penalty of perjury, of all major facilities within the state of California owned or operated by the applicant or by any entity controlling, controlled by, or under common control with the applicant and demonstrates by certifying under penalty of perjury that they are either in compliance, or on a schedule of compliance, with all applicable state and federal emission limitations and standards. The APCO may request the applicant to provide any technical information used by the applicant to certify compliance.

*(Amended June 15, 1994)*

**2-2-308** **Class I Area Requirements, PSD:** A facility for which the cumulative increases minus the contemporaneous emission reduction credits occurring since the PSD Baseline Date, are greater than zero, and which would construct in a Class I Area or within 10 kilometers (6.2 miles) of a Class I Area, and would have an impact on such area equal to or greater than 1 microgram per cubic meter, shall use BACT on the new or modified facility and shall not cause or contribute to the exceedance of any NAAQS at the point of maximum ground level impact or any PSD increment set forth in Section 2-2-232, and shall perform all analyses required by Sections 2-2-414 and 417.

*(Amended June 15, 1994)*

**2-2-309** **Denial for Air Quality Related Values, PSD:** The APCO shall deny any permit application subject to the requirements of Section 2-2-308 where it has been demonstrated by the Federal Land Manager that the permit would authorize emissions which would have an adverse impact on the air-quality-related values

(including visibility) of a Class I Area, provided that such demonstration is completed prior to the termination of the public comment period and that the APCO concurs with that demonstration.

**2-2-310** **Denial, Failure to Use BACT:** The APCO shall deny an authority to construct if the APCO finds that the application is subject to Section 2-2-301 and, after notification in writing, the applicant has not provided a control device or technique meeting the requirements defined in Section 2-2-206.

**2-2-311** **Denial, Failure to Provide Offsets:** The APCO shall deny an authority to construct if the APCO finds that the application is subject to Sections 2-2-302 or 303 and, after notification in writing, the applicant has not provided the required offsets to mitigate the emissions increase.

**2-2-312** **Denial, Failure to Meet Permit Conditions:** The APCO shall deny a permit to operate, after providing written notification to the applicant, if the equipment is operating in violation of any condition specified in the authority to construct, or if any source used to provide offsets for the project that is owned or operated by the applicant is operating in violation of any permit condition limiting emissions such that the required offsets are not being provided.

**2-2-313** **Deleted May 17, 2000**

**2-2-314** **Federal New Source Review Applicability:** The requirements of 40 CFR 51.165 are incorporated, by reference, as part of this rule.

*(Adopted June 15, 1994)*

**2-2-315** **Federal Prevention of Significant Deterioration Applicability:** The requirements of 40 CFR 51.166 are incorporated, by reference as part of this rule.

*(Adopted June 15, 1994)*

**2-2-316** **No Net Increase Status Report:** The APCO shall publish in conjunction with the triennial update of the Clean Air Plan (CAP), a report demonstrating that the District's permitting program complies with the no net increase requirements of Section 40919 (b) of the Health and Safety Code. This report shall demonstrate that sufficient offsets have been provided, as required by Section 2-2-302, for all permits issued during the previous three year CAP period. This report shall be forwarded to the California Air Resources Board, Stationary Source Division for approval.

*(Adopted June 15, 1994)*

**2-2-317** **Maximum Achievable Control Technology (MACT) Requirement:** The APCO shall not issue an Authority to Construct for a new or modified source at a Major Facility of Hazardous Air Pollutants unless the source will meet Best Available Control Technology for Toxics (TBACT), except as provided in Section 2-2-114.

*(Adopted May 17, 2000)*

## 2-2-400 ADMINISTRATIVE REQUIREMENTS

**2-2-401** **Application:** In addition to the requirements of Regulation 2-1-402, applications for authorities to construct facilities subject to Rule 2 shall include all of the following:

401.1 For new facilities, which will emit, and for a modification which will increase emissions more than 100 tons per year of carbon monoxide or 40 tons per year of either precursor organic compounds or nitrogen oxides, an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source which demonstrate that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction or modification.

401.2 The information required by the lists and criteria adopted pursuant to Section 65940 of the California Government code that are in effect on the date the application is filed.

401.3 CEQA-related information which satisfies the requirements of Regulation 2-1-426.

401.4 All information specified in 40 CFR 63.43(e), if the application is subject to the MACT requirement of Section 2-2-317.

*(Amended 11/20/91; 6/15/94; 5/17/00)*

**2-2-402** **Deleted December 21, 2004**

**2-2-403** **Deleted October 7, 1998**

**2-2-404** **Authority to Construct, Preliminary Decision:** Within 90 days following the acceptance of an application as complete, which is subject to the requirements of Section 2-2-405, or longer period necessary to satisfy the requirements of Section 2-2-414, providing that any fees required in accordance with Regulation 3 are paid, or with the consent of the applicant, such longer period as may be agreed upon, the APCO shall make a preliminary decision as to whether an authority to construct shall be approved, or denied. Final action on this application will be taken in accordance with the requirements of Section 2-2-407.

404.1 When the District is the CEQA Lead Agency for a project, the 90-day limit for issuing a preliminary decision shall be suspended until the draft EIR or Negative Declaration is available for the APCO's consideration and public review.

*(Amended 11/20/91; 5/17/00)*

**2-2-405** **Publication and Public Comment:** If the application is for a new major facility or a major modification of an existing major facility, or requires a PSD analysis, or is subject to the MACT requirement, the APCO shall within 10 days of the notification of the applicant, cause to have published in at least one newspaper of general circulation within the District, a prominent notice stating the preliminary decision of the APCO, the location of the information available pursuant to Section 2-2-406, and inviting written public comment for a 30 day period following the date of publication. Written notice of the preliminary decision shall be sent to the ARB, the regional office of the EPA and adjacent districts. A copy of this notice shall be provided to any person who requests such specific notification in writing. During this period, which may be extended by the APCO, the APCO may elect to hold a public meeting to receive verbal comment from the public. The written notice shall contain the degree of PSD increment consumed.

405.1 In addition to the above requirements, for any application for which the District is a Lead Agency under CEQA, the public notice required pursuant to this Section 2-2-405 shall provide public notice of the availability of a Draft EIR, a Negative Declaration or a Notice of Exemption, as applicable.

*(Amended May 17, 2000)*

**2-2-406** **Public Inspection:** The APCO shall make available for public inspection, at District headquarters, the information submitted by the applicant, and if applicable the APCO's analysis, and the preliminary decision to grant or deny the authority to construct including any proposed conditions, including the reasons therefore. In making information available for public inspection, the confidentiality of trade secrets, as designated by the applicant prior to completion of the application, shall be considered in accordance with Section 6254.7 of the Government Code. Furthermore, all such information shall be transmitted, upon the date of publication, to the ARB and the regional office of the EPA if the application is subject to the requirements of Section 2-2-405.

**2-2-407** **Authority to Construct, Final Action:** If the application is for a new major facility or a major modification of an existing major facility, or requires a PSD analysis, or is subject to the MACT requirement, the APCO shall within 180 days following the acceptance of the application as complete, or a longer time period agreed upon, take final action on the application after considering all public comments. Written notice of the final decision shall be provided to the applicant, the ARB and the EPA, and, if the District is a Lead Agency under CEQA, to any person who has commented on a Draft EIR. The final action will also be published in at least one newspaper of general circulation within the District, and the notice and supporting documentation shall be available for public inspection at District headquarters.

407.1 Notwithstanding the requirement of this Section 2-2-407 that the APCO shall act within 180 days after the application is accepted as complete, the APCO shall not take final action on the application for any project for which an Environmental Impact Report or a Negative Declaration has been prepared pursuant to the requirements of CEQA until a Final EIR for that project has been certified and the APCO has considered the information contained in that Final EIR, or a Negative Declaration for that project has been approved. If the specified 180 day period has elapsed prior to the certification of the

Final EIR or the approval of the Negative Declaration, the APCO shall take final action on the application within 30 days after the certification of the Final EIR or approval of the Negative Declaration.

*(Amended May 17, 2000)*

**2-2-408** **Deleted May 17, 2000.**

**2-2-409** **Requirements, Permit to Operate:** As a condition for the issuance of a Permit to Operate, the APCO shall require that the new or modified source and the sources which provide offsets be operated in the manner assumed in making the analysis required to determine compliance with this Regulation.

409.1 The permit to operate of any source used to provide offsets shall be conditioned to insure that the emission reductions will be enforceable and shall continue for the reasonably expected life of the proposed source. If offsets are obtained from a source for which there is no permit to operate, either a permit shall be obtained or a written contract shall be required between the applicant and the owner or operator of such source, which contract, by its terms, shall be enforceable by the APCO to ensure that such reductions will continue for the duration of the life of the proposed source.

**2-2-410** **Issuance, Permit to Operate:** The APCO shall issue a permit to operate a source subject to the requirements of this Rule if it is determined that any offsets required, as a condition of an authority to construct or amendment to a permit to operate, will commence no later than the initial operation of the new source or within 90 days after initial operation of the modified source, and that the offsets shall be maintained throughout the operation of the new or modified source which is the beneficiary of the offsets. Further, the APCO shall determine that all conditions specified in the authority to construct have been or will be likely complied with by any dates specified. Where a new or modified source is, in whole or in part, a replacement for an existing source on the same property, the APCO may allow a maximum of 90 days as a start-up period for simultaneous operation of the existing source and the new source or replacement.

**2-2-411** **Permit to Operate, Final Action:** The APCO shall take final action to approve, approve with conditions, or disapprove a permit to operate a source subject to this Rule within 60 days after start-up of the new or modified source. However, failure to act within the 60 day period, unless the time period is extended with the written concurrence of the applicant, shall be deemed to be a denial of the permit. Such denial may be appealed to the Hearing Board in accordance with the provisions of Regulation 2-1-410.

*(Amended November 20, 1991)*

**2-2-412** **Source Obligation, Relaxation of Enforceable Conditions:** At such time as the applicability of any requirement of this Rule would be triggered by an existing source or facility, solely by virtue of a relaxation of any enforceable limitation on the capacity of the source or facility to emit a pollutant, then the requirements of this Rule shall apply to the source or facility in the same way as they would apply to a new or modified source or facility otherwise subject to this Rule.

**2-2-413** **Deleted May 17, 2000.**

**2-2-414** **PSD Air Quality Analysis:** An application for an authority to construct a facility subject to the requirements of Sections 2-2-304, 305, 306 or 308 shall contain the following:

414.1 A modeling analysis, as defined in Section 2-2-222, demonstrating to the satisfaction of the APCO the air quality impacts of the new or modified facility (including impacts of non-criteria pollutants if required under Section 2-2-306). The analysis shall include meteorological and topographic data necessary to estimate such impact. If the maximum air quality impacts of the new or modified facility do not exceed the significance levels for air quality impacts, as defined in Section 2-2-233, no further analysis under this Section will be required unless the facility is subject to the Class I area requirements of Section 2-2-308.

414.2 A demonstration by modeling to the satisfaction of the APCO that the allowable emission increases from the new or modified facility, in conjunction with all other applicable emissions, would not cause or contribute to a

violation of an air quality standard or an exceedance of any applicable PSD increment. A new or modified facility will be considered to cause or contribute to a violation of an air quality standard when the increase in emissions would cause a significant air quality impact at any locality that does not or would not meet the applicable air quality standard.

414.3 For determining whether the emission increases from the new or modified facility would cause or contribute to an air quality standard violation or an exceedance of a PSD increment, an analysis of the existing air quality in the impact area of the new or modified facility that includes one year of continuous ambient air quality monitoring data. The continuous air quality monitoring data shall have been gathered over a period of at least one year preceding the receipt of a complete application. The APCO may approve a shorter period (but not less than four months) provided that the period of monitoring includes the time frame when maximum concentrations are expected. The APCO may approve modeling in lieu of ambient air quality monitoring for pollutants for which no air quality standard exists.

414.4 For pollutants for which PSD increments have been established, a PSD increment consumption analysis that includes:

4.1 Establishment of the baseline area(s) affected by the new and modified facility, and the corresponding baseline date(s);

4.2 An analysis of the air quality impact of all increment-consuming emissions within the impact area of the new or modified facility, and those increment-consuming emissions outside the impact area that may have a significant air quality impact within the impact area; and,

4.3 An analysis of the air quality impact, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since the baseline date in the impact area of the new or modified facility.

**2-2-415** **Notice to EPA and Federal Land Manager:** On the date of a complete application subject to Section 2-2-308, the APCO shall provide a copy of the complete application to the EPA, the Federal Land Manager for the affected Class I Area, and to the federal official charged with direct responsibility for management of any lands within the Class I area. The APCO shall also send a copy of the preliminary decision and the APCO's analysis to the above agencies.

**2-2-416** **Report, PSD Increment Consumption:** The District shall conduct an annual review of the increment status for each attainment pollutant, and the APCO, upon request of the Board of Directors, shall provide a report on the consumption of PSD increments which have occurred during the period of interest.

**2-2-417** **Visibility, Soils, and Vegetation Analysis:** An application for a permit subject to the requirements of Section 2-2-414 shall contain an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the new or modified source and the general commercial, residential, industrial and other growth associated with the source or modification. The applicant need not provide an analysis of the impact on vegetation if it has no significant commercial or recreational value.

**2-2-418** **PSD Analysis Stack Heights:** For the purposes of modeling, stack heights beyond what is required by good engineering practices shall not be allowed. This requirement should not be perceived to be a limit on the actual constructed height of a stack. The method to calculate good engineering stack height is referenced in Section 2-2-602.

**2-2-419** **Permit Conditions:** The APCO may require any permit condition necessary to insure compliance with this Rule to be included in an authority to construct or permit to operate. This may include conditions controlling the operation of the source, of its abatement equipment, or of sources used to provide mitigation (offsets). Conditions may have a future effective date and may be made conditional on the results of source tests, ground level monitors or public complaints.

419.1 All emission reduction credits shall be enforceable by permit conditions; such permit conditions shall constitute applicable requirements of the State

Implementation Plan for purposes of Section 113 and 304 of the Clean Air Act and are enforceable in the same manner as other SIP requirements.

*(Amended June 15, 1994)*

**2-2-420 Deleted March 1, 2000**

**2-2-421 Offset Deferral, Annual Permit Renewal:** Whenever offsets are required by Section 2-2-302 or 303, a person has the option to defer providing the offsets until the time of the annual permit renewal provided:

421.1 The facility demonstrates that they have valid Banking Certificates adequate to cover their offset obligation. Offsets deferred under the provisions of this Section shall be provided by the facility at least 30 days prior to the date of annual permit renewal, and

421.2 The facility does not have a cumulative increase greater than 15 tons per year for the pollutant or pollutants subject to the offset requirement(s).

*(Adopted June 15, 1994)*

**2-2-422 Offset Refunds:** Whenever an authorized source is either not constructed or is constructed and operated to result in lower emissions than the amount authorized, the APCO shall issue a certificate refunding the excess offsets. The APCO shall add appropriate conditions to the operating permits to make the new emission levels enforceable.

*(Adopted October 7, 1998)*

**2-2-423 Demonstration of Offset Program Equivalence**: By March 1 of each year, the District shall submit to EPA a demonstration that offsets provided for all new and modified sources within the District, less adjustments to those offsets for federal purposes occurring between credit generation and use, exceed federal offset requirements for new major sources or major modifications at major stationary sources. Adjustment to emission reductions for federal purposes will be required if any of the following occur between the time the credit is generated and the time the credit is used:

423.1 BAAQMD adopts a relevant measure or rule that is required for purposes of federal attainment demonstration requirements.

423.2 A relevant rule or measure is approved into the State Implementation Plan applicable in the BAAQMD;

423.3 EPA promulgates a relevant final rulemaking for either a New Source Performance Standard or a Maximum Achievable Control Technology Standard.

The demonstration shall include:

423.4 Emission increases represented by all authorities to construct new major facilities and major modifications at major facilities issued during the three calendar years preceding the demonstration date;

423.5 A list of all emission reductions used to offset those emission increases;

423.6 The emission baselines that were used to calculate the emission reduction;

423.7 The source type, size and category that had generated the emission reduction credit;

423.8 All relevant rules that have been adopted or promulgated since the emission reduction had occurred.

423.9 Adjustments to emission reduction fro federal purposes for all affected projects.

423.10 All of the above for as many non-major projects as are needed to demonstrate equivalence.

If the analysis fails to make the required demonstration, the District shall provide sufficient offsets to make up the difference out of the small facility bank. If the small facility bank does not contain the necessary surplus emission reductions, the District shall obtain the necessary surplus emission reductions.

*(Adopted May 17, 2000)*

**2-2-500 MONITORING AND RECORDS**

**2-2-501 PSD Pre-Construction Ambient Air Monitoring:** An applicant subject to the requirements of subsection 2-2-414.3 shall meet the following requirements:

501.1 Prior to commencing pre-construction ambient air monitoring, receive written approval from the APCO regarding the selection and operation of monitoring stations.

501.2 Operate the monitoring stations in accordance with the provisions of Appendix B to 40 CFR 58. The APCO may approve the use of District air monitoring data as part of the PSD air quality analysis required by Section 2-2-414.

**2-2-502** **PSD Post-Construction Monitoring:** The owner or operator of a facility subject to the requirements of Section 2-2-414 shall, after construction of the facility or modification, conduct such ambient air quality monitoring as the APCO specifies in the authority to construct or the permit to operate. The monitoring shall determine the effect emissions from the facility or modification may have, or are having, on air quality in the area. All air monitoring shall be performed in accordance to the Manual of Procedures, Volume VI and 40 CFR Appendix B.

**2-2-600** **MANUAL OF PROCEDURES**

**2-2-601** **Ambient Air Quality Monitoring:** Any person subject to the ambient air quality monitoring requirements of this Rule shall use the methods prescribed in the Manual of Procedures, Volume VI.

**2-2-602** **Good Engineering Practice (GEP) Stack Height:** The method for calculating GEP stack height is contained in the FEDERAL REGISTER: Volume 50, Number 130; Monday, July 18, 1985.

**2-2-603** **PSD Air Quality Evaluation Procedure:** As a guideline to preparing an air quality impact analysis the applicant is encouraged to review "Guidelines for Air Quality Maintenance Planning and Analysis," Volume 10 (Revised): Procedures for Evaluating Air Quality Impact of New Stationary Sources, EPA-450/4-77-001.

**2-2-604** **Emission Increase Calculation Procedures, New or Modified Sources:** The APCO shall determine the annual emission increase, expressed as tons per year, from:

604.1 A new source based on the maximum emitting potential of the new source or the maximum permitted emission level of the new source, approved by the APCO, subject to federally enforceable limiting conditions.

604.2 A modified source by subtracting either the baseline annual emission rate, as calculated using the methodology in Section 2-2-605, from the new maximum permitted emission level of the modified source, approved by the APCO, subject to federally enforceable limiting conditions.

*(Amended 6/15/94; 5/17/00)*

**2-2-605** **Emission Calculation Procedures, Emission Reduction Credits:** The following methodology shall be used to calculate emission reduction credits.

605.1 The baseline period consists of the 3 year period immediately preceding the date that the application is complete (or shorter period if the source is less than 3 years old). The applicant must have sufficient verifiable records of the source's operation to substantiate the emission rate and throughput during the entire baseline period.

605.2 Baseline throughput is the lesser of:

2.1 actual average throughput during the baseline period; or

2.2 average permitted throughput during the baseline period, if limited by permit condition.

605.3 Baseline emission rate, expressed in the units of mass of emissions per unit of throughput, is the average actual emission rate during the baseline period. Periods where the actual emission rate exceeded regulatory or permitted limits shall be excluded from the average.

605.4 Baseline Throughput and Emission Rate - Fully Offset Source: For a source which has, contained in a permit condition, an emission cap or emission rate which has been fully offset by the facility (without using emission reductions from the Small Facility Banking Account), the baseline throughput and baseline emission rate shall be based on the levels allowed by the permit condition.

605.5 The adjusted baseline emission rate shall be determined by adjusting the baseline emission rate downward, if necessary, to comply with the most stringent of RACT, BARCT, and District rules and regulations in effect or contained in the most recently adopted Clean Air Plan.

605.6 Emission reduction credits shall be the difference between the adjusted baseline emission rate times the baseline throughput, and the emission cap or emission rate accepted by the applicant as a federally enforceable limiting conditions.

*(Amended 6/15/94; 5/17/00)*

**2-2-606** **Emission Calculation Procedures, Offsets:** Except as provided by the offset deferral provision of Section 2-2-421, before the APCO may issue an authority to construct for a new or modified source, offsets shall be provided, as required by Sections 2-2-302, 303 or 313 by the applicant from credits in the District's Emissions Bank and/or from contemporaneous emission reduction credits which qualify in accordance with Sections 2-2-201 and 605, or by the District from the small facility banking account for the amounts calculated as follows:

606.1 For precursor organic compounds (POC) and nitrogen oxides ($NO_x$) for the total of all emission increases as determined in Section 2-2-604 plus any pre-existing cumulative increase from April 5, 1991, multiplied by the offset ratio required by Section 2-2-302.

606.2 If required by Section 2-2-303, for, $PM_{10}$, and sulfur dioxide for the total of all emission increases as determined in Section 2-2-604 multiplied by the appropriate offset ratio specified in Section 2-2-303.

Emission offsets provided in excess of those required, which meet the requirements of a bankable reduction per Regulation 2-4, may be banked. Banking fees shall be waived for this transaction.

*(Amended 6/15/94; 5/17/00)*

**2-2-607** **Emission Calculation Procedures, Emission Reduction Credits for Mobile Sources:** Emission reduction credits for mobile sources shall be determined by the Mobile Source Emission Reduction Credits procedures published February 1994 (or subsequent revisions) by the California Air Resources Board or other District approved procedures in the Manual of Procedures.

*(Adopted June 15, 1994)*

**2-2-608** **Deleted May 17, 2000**

# EXHIBIT C

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
(Vice Chairperson)
Nate Miley
Shelia Young

CONTRA COSTA COUNTY
Mark DeSaulnier
Mark Ross
Gayle Uilkema

MARIN COUNTY
Harold C. Brown, Jr.

NAPA COUNTY
Brad Wagenknecht

SAN FRANCISCO COUNTY
Chris Daly
Tony Hall
Leland Yee

SAN MATEO COUNTY
Jerry Hill
Marland Townsend
(Secretary)

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Randy Attaway
(Chairperson)
Liz Kniss
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
EXECUTIVE OFFICER/
AIR POLLUTION
CONTROL OFFICER

July 24, 2001

**Mirant Delta, LLC**
**P O Box 1687**
**Antioch, CA 94509**

Attention: **Joseph Bittner**

Application Number: **1000**
Plant Number: **18**
Equipment Location:
**1456 Wilbur Avenue**
**Antioch, CA 94509**

Dear Applicant:

This is your Authority to Construct the following:

S-41 **Combustion Gas Turbine #1, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.**

S-42 **Heat Recovery Steam Generator #1, 395 MM Btu per hour, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.**

S-43 **Combustion Gas Turbine #2, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.**

S-44 **Heat Recovery Steam Generator #2, 395 MM Btu per hour, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.**

S-45 **Gas-Fired Fuel Preheater, 12 MM Btu per hour.**

S-46 **10-Cell Wet Cooling Tower, 125,000 gallons per minute**

The equipment described above is subject to condition no. 18138.

**Notification**

**Please contact your assigned Permit Engineer,** listed in the correspondence section of this letter, by phone, by fax, or in writing at least three days before the initial operation of the equipment so that we may observe the equipment in operation and verify conformance with the Authority to Construct. Operation includes any start-up of the source for testing or other purposes. Operation of equipment without notification to the District may result in enforcement action. **Do not send start-up notifications to the Air Pollution Control Officer.**

**Start-up Period**

After receipt of the start-up letter required above, this Authority to Construct authorizes operation during the start-up period from the date of initial operation noted in your start-up letter until the Permit to Operate is issued, up to a maximum of 90 days. All conditions (specific or implied) of the Authority to Construct are in effect during the start-up period.

Application: 1000
July 24, 2001

**Fees**
District Regulation 3 requires a fee for each new Permit to Operate. You will be invoiced upon receipt of your start-up letter. No permits will be issued until all outstanding fees are paid.

**Implied Conditions**
In the absence of specific permit conditions to the contrary, the throughputs, fuel and material consumption, capacities, and hours of operation described in your permit application will be considered maximum allowable limits. A new permit will be required before any increase in these parameters, or change in raw material handled, may be made.

**Expiration**
In accordance with Regulation 2-1-407, this Authority to Construct expires two years from the date of issuance unless substantial use of the authority has begun.

**Confidentiality**
Unless you have already designated specifically identified materials in your permit application as confidential, under the California Public Records Act, all data in your permit application, the permit itself and all permit conditions will be considered a matter of public record and may be disclosed to a third party. Please contact you permit reviewer immediately if you wish to amend your permit application submittals or to designate certain permit conditions as confidential. Unless we hear from you within ten (10) calendar days of this letter, except for materials which have been previously designated as confidential, you shall be deemed to have waived any claim of confidentiality with respect to all materials in the District's files relating to this permit application.

**Right of Entry**
The Air Pollution Control Officer of the Bay Area Air Quality Management District, the Chairman of the California Air Resources Board, the Regional Administrator of the Environmental Protection Agency, and/or their designees, upon presentation of credentials, shall be granted the right of entry to any premises on which an air pollution source is located for the purposes of:

A. The inspection of the source
B. The sampling of materials used at the source
C. The conduction of an emissions source test
D. The inspection of any records required by District rule or permit condition.

**Correspondence**
Please include you application number with any correspondence with the District. The District's regulations may be viewed online at www.baaqmd.gov/regs/rulereg.htm. If you have any questions on this matter, please call **Dick Wocasek, Air Quality Engineer II at (415) 749-4984. Startup information may be faxed to the Permit Division at 415-749-5030.**

Very truly yours,

Ellen Garvey
Executive Officer/
Air Pollution Control Officer

by
Permit Services Division

FRW: ilh

COND# 18138 ----------

CCPP Unit 8
Permit Conditions

Definitions:

| | |
|---|---|
| 1-hour period: | Any continuous 60-minute period beginning on the hour. |
| Calendar Day: | Any continuous 24-hour period beginning at 12:00 AM or 0000 hours. |
| Year: | Any consecutive twelve-month period of time |
| Heat Input: | All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in Btu/scf. |
| Rolling 3-hour period: | Any three-hour period that begins on the hour and does not include start-up or shutdown periods. |
| Firing Hours: | Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments. |
| MM Btu: | million British thermal units |
| Gas Turbine Start-up Mode: | The lesser of the first 256 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 27(b) and 27(d). |
| Gas Turbine Shutdown Mode: | The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 27(b) through 27(d) until termination of fuel flow to the Gas Turbine. |
| Specified PAHs: | The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.<br>Benzo[a]anthracene<br>Benzo[b]fluoranthene |

Benzo[k]fluoranthene
Benzo[a]pyrene
Dibenzo[a,h]anthracene
Indeno[1,2,3-cd]pyrene

Corrected Concentration: The concentration of any pollutant (generally NOx, CO, or NH3) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% O2 by volume on a dry basis.

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the CCPP Unit#8 construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.

Commissioning Period: The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.

Precursor Organic Compounds (POCs): Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate

CEC CPM: California Energy Commission Compliance Program Manager

CCPP Unit#8: Contra Costa Power Plant Unit 8

Conditions for the Commissioning Period

1. The owner/operator of the CCPP Unit 8 (CCPP Unit#8) shall minimize emissions of carbon monoxide and nitrogen

oxides from S-41 and S-43 Gas Turbines and S-42 and S-44 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period. Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 47 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-41 & S-43 Gas Turbine combustors and S-42 & S-44 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-11 and A-13 SCR Systems and A-12 and A-14 CO Oxidation Catalyst Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-41 & S-43 Gas Turbines and S-42 & S-44 Heat Recovery Steam Generators.

4. Coincident with the as designed operation of A-11 & A-13 SCR Systems, pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall comply with the NOx and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the CCPP Unit#8 shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired preheater. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NOx combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

6. During the commissioning period, the owner/operator of the CCPP Unit#8 shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

- firing hours for each gas turbine and each HRSG
- fuel flow rates to each train
- stack gas nitrogen oxide emission concentrations at P-11 and P-12
- stack gas carbon monoxide emission concentrations P-11 and P-12
- stack gas carbon dioxide concentrations P-11 and

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44). The owner/operator shall use District-approved methods to calculate heat input rates, NOx mass emission rates, carbon monoxide mass emission rates, and NOx and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous emission monitors specified in condition 6 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44). After first firing of the turbines, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NOx emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-41 Gas Turbine and S-42 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-11 SCR System and/or A-12 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-41 Gas Turbine and S-42 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

9. The total number of firing hours of S-43 Gas Turbine and S-44 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-13 SCR System and/or A-14 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-43 Gas Turbine and S-44 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

11. Combined pollutant mass emissions from the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-41 & S-43).

| | | | |
|---|---|---|---|
| NOx(as NO2) | 8,400 | pounds/calendar day | 400 pounds/hour |
| CO | 13,000 | pounds/calendar day | 584 pounds/hour |
| POC(as CH4) | 535 | pounds/calendar day | |
| PM10 | 624 | pounds/calendar day | |
| SO2 | 297 | pounds/calendar day | |

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 21. The source test shall determine NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-41 & S-43) and the Heat Recovery Steam Generators (HRSGs; S-42 & S-44)

13. The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on natural gas. (BACT for SO2 and PM10)

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,227 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for NOx)

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 49,950 MM Btu per calendar day. (PSD for PM10)

16. The combined cumulative heat input rate for the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall not exceed 34,900,000 MM Btu per year. (Offsets)

17. The HRSG duct burners (S-42 and S-44) shall not be fired unless its associated Gas Turbine (S-41 and S-43, respectively) is in operation. (BACT for NOx)

18. Except as provided in Condition No. 8, S-41 Gas Turbine and S-42 HRSG shall be abated by the properly operated and properly maintained A-11 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-11 catalyst bed has reached minimum operating temperature. (BACT for NOx)

19. Except as provided in Condition No. 9, S-43 Gas Turbine and S-44 HRSG shall be abated by the properly operated and properly maintained A-13 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-13 catalyst bed has reached minimum operating temperature. (BACT for NOx)

20. The Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

(a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO2) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO2) at P-12 (the combined exhaust point for the S-43 Gas Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. (PSD for NOx)

(b) The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O2, averaged over any 1-hour period. (BACT for NOx)

(c) Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed 0.013 lb./MM Btu (HHV) of natural gas fired or 29.22 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

(d The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed 6 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. (BACT for CO)

(e) Ammonia (NH3) emission concentrations at P-11 and P-12 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The

correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (TRMP for NH3)

(f) Precursor organic compound (POC) mass emissions (as CH4) at P-11 and P-12 each shall not exceed 5.6 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)

(g) Sulfur dioxide (SO2) mass emissions at P-11 and P-12 each shall not exceed 6.18 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)

(h) Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or 0.00588 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed 13 pounds per hour or 0.00584 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-41 and S-43) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

| | Cold Start-Up (lb./start-up) | Hot Start-Up lb./start-up) | Shutdown (lb./shutdown) |
|---|---|---|---|
| Oxides of Nitrogen (as NO2) | 452 | 189 | 59 |
| Carbon Monoxide (CO) | 990 | 291 | 73 |
| Precursor Organic Compounds (as CH4) | 109 | 26 | 6 |

22. The Gas Turbines (S-41 and S-43) shall not be in start-up mode simultaneously. (PSD)

23. Total combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44), including emissions generated during Gas Turbine start-ups and shutdowns shall not exceed the following limits during any calendar day:

(a) 1,994 pounds of NOx (as NO2) per day (CEQA)

(b) 3,602 pounds of CO per day (PSD)

(c) 468 pounds of POC (as CH4) per day (CEQA)

(d) 624 pounds of PM10 per day (PSD)

(e) 297 pounds of SO2 per day (BACT)

24. Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44)and the Fuel Gas Preheater (S-45) and the Cooling Tower (S-46), including emissions generated during gas turbine start-ups and

shutdowns shall not exceed the following limits during any consecutive twelve-month period:

(a) 174.3 tons of NOx (as NO2) per year (Offsets, PSD)
(b) 259.1 tons of CO per year (Cumulative Increase)
(c) 46.6 tons of POC (as CH4) per year (Offsets)
(d) 112.2 tons of PM10 per year (Offsets, PSD)
(e) 48.5 tons of SO2 per year (Cumulative Increase)

25. Toxic and HAP Emission Limits

25.1. The maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limits:

4,102 pounds of formaldehyde per year
506 pounds of benzene per year
38 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

25.2. The maximum projected annual Hazardous Air Pollutant (HAP) emissions from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limit:

20,000 pounds of hexane per year
(US-CAA, Section 112(g))

Conformance with this limit shall be verified by the source testing in condition 32.

26. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 23(a), 23(b), 24(a), and 24(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and

Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(b) Carbon Dioxide ($CO_2$) or Oxygen ($O_2$) concentrations, Nitrogen Oxides (NOx) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.
(c) Ammonia injection rate at A-11 and A-13 SCR Systems
(d) Steam injection rate at S-41 & S-43 Gas Turbine Combustors

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and average hourly pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(e) Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(f) Corrected NOx concentrations, NOx mass emissions (as $NO_2$), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.

Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and (26f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.
(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-41, S-42, S-43, and S-44) combined.
(i) the average NOx mass emissions (as $NO_2$), CO mass emissions, and corrected NOx and CO emission concentrations for every clock hour and for every rolling 3-hour period.
(j) on an hourly basis, the cumulative total NOx mass emissions (as $NO_2$) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.
(k) For each calendar day, the average hourly Heat Input Rates, Corrected NOx emission concentrations, NOx mass emissions (as $NO_2$), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

(l) on a daily basis, the cumulative total NOx mass emissions (as NO2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c) through 23(e), and 24(c) through 24(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM10) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO2) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 26, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM10, and SO2 emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-41, S-42, S-43, and S-44) combined.
(b) on a daily basis, the 365 day rolling average cumulative total POC, PM10, and SO2 mass emissions, for all four sources (S-41, S-42, S-43, and S-44) combined.

(Offsets, PSD, Cumulative Increase)

28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of Formaldehyde, Benzene, and Specified PAHs. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 34,900,000 MM Btu/year and the highest emission factor (pounds of pollutant per MM Btu of Heat Input) determined by any source test of the S-41 & S-43 Gas Turbines and/or S-42 & S-44 Heat Recovery Steam Generators. If this calculation method results in an unrealistic mass emission rate (the highest emission factor occurs at a low firing rate) the applicant may use an alternate calculation, subject to District approval. (TRMP)

29. Within 60 days of start-up of the CCPP Unit#8, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 to determine the corrected ammonia (NH3) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding NH3 emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and

100% load) to establish the range of ammonia injection rates necessary to achieve NOx emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

30. Within 60 days of start-up of the CCPP Unit#8 and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM10) emissions including condensable particulate matter. (BACT, offsets)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM10 emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 60 days of start-up of the CCPP Unit#8 and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 28 for any of the compounds listed below are less than the

BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

| | | |
|---|---|---|
| Benzene | less than or equal | 26.8 pounds/year |
| Formaldehyde | less than or equal | 132 pounds/year |
| Specified PAHs (TRMP) | less than or equal | 0.18 pounds/year |

33. The owner/operator of the CCPP Unit#8 shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

34. The owner/operator of the CCPP Unit#8 shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

35. The owner/operator of the CCPP Unit#8 shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

36. The stack height of emission points P-11 and P-12 shall each be at least 195 feet above grade level at the stack base. (PSD, TRMP)

37. The Owner/Operator of CCPP Unit#8 shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Regulation 1-501)

38. Within 180 days of the issuance of the Authority to Construct for the CCPP Unit#8, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 26, 29, 30 and 32. All source testing and monitoring shall

# Exhibit No. 321

BAAQMD Brief on Jurisdictional Issues submitted to the US EPA Environmental Appeals Board, dated June 22, 2009, filed June 30, 2009, including Declaration of Alexander G. Crockett, Esq., dated June 22, 2009, filed June 30, 2009

**BEFORE THE ENVIRONMENTAL APPEALS BOARD**
**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**WASHINGTON, D.C.**

| | | |
|---|---|---|
| In the matter of<br>Gateway Generating Station | )<br>)<br>)<br>)<br>) | PSD Appeal No. 09-02 |

# BAAQMD BRIEF ON JURISDICTIONAL ISSUES

Pursuant to the Environmental Appeals Board's Order of June 18, 2009, Respondent Bay Area Air Quality Management District ("District") submits this Brief on Jurisdictional Issues. For the reasons explained herein, the District submits that the Environmental Appeals Board lacks jurisdiction over the Petition filed in this matter under 40 C.F.R. section 124.19. The Petition should therefore be dismissed.

## I. SUMMARY

The Board was correct in observing that "it appears as though the EAB lacks jurisdiction over this matter." (Order at p. 4.) The Board does indeed lack jurisdiction, for several reasons. For one, as the Board observed, the Petition is untimely in that is was not filed until many years after the permit was issued. In addition, the initial permit term expired when construction on the facility ceased for over 18 months, and so even if the Board can overlook the lack of timeliness, any issues concerning the validity of the permit at this point are moot. For both these reasons, the Board lacks jurisdiction to review the permit at this point in time under 40 C.F.R. section 124.19. The Petition does not allege any other basis for jurisdiction because it does not identify any other final PSD permitting action for the Board to adjudicate.

The Board should therefore dismiss the Petition for lack of jurisdiction. At this late stage, the appropriate vehicle for addressing the claims of non-compliance with the Clean Air Act's PSD requirements raised in the Petition is through the Act's enforcement mechanism, not

through an appeal of a nearly eight-year-old permit. EPA Region 9 has already begun the enforcement process, and this Board should dismiss the Petition here and let the issues it raises be resolved in that forum.

## II. FACTUAL BACKGROUND

As detailed in the Petition for Review, the District issued a PSD Permit for the Gateway Generating Station on July 24, 2001.[1] (*See* Petition at p. 6 and Exh. 1.) The PSD Permit was issued under a Delegation Agreement with EPA Region 9, and was issued along with a District "Authority to Construct" permit under an integrated state/federal permitting system. This integrated PSD/Authority to Construct permit system has been described by this Board in *In re Russell City Energy Center*, PSD Appeal No. 08-01, 14 E.A.D. __ (July 29, 2008). The Delegation Agreement provides that under this integrated system "permits issued in accordance with the PSD provisions of [the District's New Source Review Rule, District Regulation 2, Rule 2, are] deemed to meet the federal PSD permit requirements . . . ." (*U.S. EPA – Bay Area Air Quality Management District Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21* ("Delegation Agreement"), Exh. A to Declaration of Alexander G. Crockett, Esq., submitted concurrently herewith ("Crockett Dec'l"), at ¶ I.1.)[2] The transmittal letter for the integrated permit document did not explicitly cite the PSD element of the District's permitting action, but the fact that the document was issued to serve as the PSD permit is clear in the actual permit conditions themselves, many of which cite "PSD" as their legal basis, as well as from numerous discussions

[1] The facility was originally owned by Mirant Delta, LLC, and was known as Contra Costa Power Plant Unit 8. (*See* Petition at p. 6; Exh. 1.) The facility was subsequently transferred to PG&E and renamed the Gateway Generating Station. (*See* Petition at p. 6.) For simplicity, the District refers to the facility generally as "Gateway" throughout this document.

[2] Exhibit 1 to the Crockett Declaration is the current version of the Delegation Agreement. The Agreement has existed in several versions over different time periods relevant to this Petition, and each version has included language about permits issued in accordance with the PSD provisions of the District's NSR regulations being deemed to meet federal PSD permit requirements. Paragraph I.1. of the agreement explains that the quoted language regarding the delegated permitting system is applicable back to the original delegation in 1986.

of the PSD elements of the integrated permitting process throughout the record for this permitting action. (*See* discussion in Section III.B., *infra*, for further details.)

The project owner commenced construction after it received its Authority to Construct/PSD Permit, but subsequently stopped work for a period of greater than 18 months. (*See* Petition at p. 6.[3]) The District periodically issued extensions of the District Authority to Construct during the period when construction had ceased (*see* Petition at pp. 9-10 & Exh. 4), and intended that they would be effective to extend the PSD Permit as well in accordance with the provision in the Delegation Agreement cited above.

The project owner then re-started construction work on the facility in approximately February of 2007. (*See* Petition at p. 6.[4]) At the time, the District (and apparently the project owner as well) was under the impression that the extensions to the Authority to Construct that had been granted had been effective to extend the PSD Permit as well pursuant to the Delegation Agreement, and that the PSD Permit therefore remained in force and effect to authorize construction. Subsequently, the project owner also submitted an application for an amendment to the Authority to Construct and PSD Permit in December of 2007 requesting, *inter alia*, increases in the emissions limits included in the initial permit. (*See* Petition at p. 6 & Exh. 6, Attachment A.) The District began to process that amendment application (again, under the assumption that the PSD Permit had been validly extended pursuant to the Delegation Agreement and was still in effect), and issued proposed amendments for public review and comment. (*See* Petition at p. 6 & Exh. 2.) The project owner ultimately withdrew the application, however, on February 13, 2009. (*See* Letter from Thomas Allen, PG&E, to Brian Bateman, BAAQMD, Feb. 13, 2009, Exh. B to Crockett Dec'l.) The project owner cited its experience showing that it could comply with the conditions imposed in the original Authority to

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[3] The District has not confirmed the exact dates on which construction ceased and recommenced as listed in the Petition, but understands that the duration of the cessation was over 18 months as Petitioner alleges.

[4] Again, the District has not verified the exact dates specified in the Petition, but does not understand them to be incorrect at this stage.

Construct and PSD permit, which indicated that the increases in emission limits it had requested were unnecessary. (*See id.*) The project owner therefore went ahead and completed construction, and began operating the facility, based on the California and Federal permit authorizations that were originally issued in 2001 and were purportedly extended by the District's issuance of Authority to Construct extensions periodically since that time.

Subsequent to PG&E's withdrawal of the permit application, in communications between the District and EPA Region 9, EPA Region 9 has informed the District that it does not consider the extensions of the Authority to Construct under District regulations to have been effective to extend the facility's Federal PSD Permit. (*See* Letter from Brian C. Bunger, Esq., BAAQMD District Counsel, to Nancy Marvel, Esq., EPA Region 9 Regional Counsel, May 21, 2009, attached as Exhibit C to Crockett Dec'l.) Given the District's obligation to follow EPA Region 9's guidance with regard to Federal PSD permitting matters (*see* Delegation Agreement, Crockett Dec'l. Exh. A, at ¶ VII.1.), the District is now following this interpretation, as of receiving notice of it. In light of this recent interpretation, it appears in hindsight that the PSD Permit for the facility expired when construction ceased for more than 18 months, and was not effectively extended by the Authority to Construct extensions that the District issued periodically during the time construction was on hold. Given that, under EPA Region 9's current interpretation, the PSD Permit had apparently expired by the time construction was restarted, it appears that construction occurred without a current, valid PSD Permit as required by the PSD Provisions of the Federal Clean Air Act, CAA § 165, 42 U.S.C. § 7475. EPA Region 9 has begun enforcement action regarding this apparent non-compliance and is currently in settlement negotiations with PG&E on this issue. (*See* Intervenor Pacific Gas and Electric Company's Motion For Stay, Docket Entry No. 18, at p. 1.)

Petitioner now seeks to bring this situation before the Environmental Appeals Board in the form of a PSD Permit appeal under 40 C.F.R. Section 124.19. His Petition comes several months after the facility completed construction; several years after the PSD Permit for the facility apparently expired, a point on which there is now no disagreement among Petitioner, the

District and EPA Region 9; and while EPA Region 9 is undertaking enforcement action to address the apparent Clean Air Act non-compliance concerns Petitioner raises.

## III. THE EAB LACKS JURISDICTION BECAUSE THE PETITION IS UNTIMELY, AND ALSO BECAUSE THE ISSUES RAISED IN THE APPEAL ARE MOOT.

The Board's June 18, 2009, Order requested briefing on three issues. The District addresses each of them in turn below. In summary, the District agrees with the Board's initial assessment that it lacks jurisdiction over this matter under 40 C.F.R. Section 124.19. (*See* Order at p. 4.) The Board lacks jurisdiction over the Petition because it is untimely, having been filed nearly eight years after the permit was issued and after the facility has completed construction; and for the additional reason that it is moot, as the initial permit has long since expired and there have not been any further final permitting actions for the Board to adjudicate in a permit appeal under Section 124.19.

### A. An Appeal From A PSD Permit Issued in 2001 Is Not Timely When It Is Filed In 2009

40 C.F.R. Section 124.19 requires that any appeal of a PSD permit must be filed within 30 days. Here, it is nearly eight years since the permit was issued in July of 2001. The Board lacks jurisdiction over a Petition filed so long after the permit was issued.

Petitioner argues that he should be excused from the timeliness requirement because he claims that he was not given adequate notice of the draft permit, and as a result did not have notice that the appeal clock had started to run at the time the final permit was issued. (*See* Petition at p. 7.) His argument is that the allegedly defective notice means that he is not subject to any time limit whatsoever on appealing the permit.[5] This cannot be the meaning of Section 124.19, as it would completely eviscerate any element of finality in PSD permit proceedings. It would require the Board to hear appeals of long-settled permits issued years ago anytime a

[5] Petitioner seeks to appeal a permit here nearly eight years after its issuance, but by logical extension of his theory, he would also claim to be able to challenge permits issued 18 years or 28 years ago or more. His argument is that he can appeal any permit where he can allege that in hindsight there may have been procedural defects in the permit issuance process, going right back to the very inception of the PSD program.

Petitioner can claim in hindsight that there may have been alleged procedural defects in permit issuance, even for facilities that have since completed construction and have begun operating. But the PSD permit is a preconstruction permit, and it would make no sense to have to adjudicate such permits where construction has already occurred. In such a case, there would be nothing to be gained by determining in the permit appeal context that, in hindsight, there may have been deficiencies in the permit issuance process. A meritorious claim that a facility had been built without proper authorization would, of course, be an important Clean Air Act compliance concern that the agency would want to address appropriately. But the mechanism for doing so necessarily has to be through the enforcement context. Even if the EAB were to hear an appeal in such a case and determine that there were defects in permit issuance, it would have no effect on the ground absent an enforcement action for construction without valid PSD authorization. The Board should not devote resources to retrospectively considering the validity of preconstruction permits in the permit appeal context so long after the fact and after the facility has been constructed, where the only meaningful way to remedy any non-compliance with PSD permitting requirements is in the enforcement context. 40 C.F.R. Section 124.19 cannot have been intended to extend the permit appeal process to cover such situations.

But ultimately, even if the Board were to excuse Petitioner's failure to appeal at the time when the permit was issued notwithstanding these arguments, the Board would still lack jurisdiction here because the permit term expired several years ago and so any Petition challenging it at this stage is moot. As Petitioner concedes, construction of the facility began after the Federal PSD Permit was initially issued, but then ceased for over 18 months. (*See* Petition at p. 6.[6]) As a matter of law, the PSD Permit term expired as a result of this cessation of construction by operation of 40 C.F.R. section 52.21(r)(2). Once a permit has expired, there is nothing left for the EAB to review. (*See In re GSX Services of South Carolina, Inc.*, RCRA

[6] The Petition alleges that construction ceased in February of 2002. Again, the District has not verified the exact dates, but agrees that the cessation in construction exceeded 18 months in duration.

Appeal No. 89-22, 4 E.A.D. 451, 453 n.3 (EAB 1992) (noting in *dicta* that permit expiry can render appeal under 40 C.F.R. § 124.19 moot); *In re 539 Alaska Placer Miners etc.*, NPDES Appeal Nos. 90-10 & 90-11, Slip. Op., 1992 EPA App. LEXIS 48, *2 (CJO Feb. 26, 1992) (dismissing appeal issue as moot where NPDES permit expired before hearing).)[7] The Board therefore lacks jurisdiction over the Petitioner's challenge to the permit that was initially issued, because the validity of that permit is now moot. There would be no purpose to be served by adjudicating such an appeal because there is no meaningful remedy that the Board could grant for any alleged defects in the permit as issued in 2001. The Board could not meaningfully remand the permit to the District to correct any deficiencies at this late stage, so long after the initial application was submitted and after the permit was issued, ran its term, and expired. Nor could the Board grant any meaningful relief in the form of an advisory opinion that the initial permit is not valid at this time, as neither the District and Petitioner dispute its validity now because of the expiration caused by the cessation of construction. Thus, to the extent that the Board can excuse the Petition's un-timeliness, it should still dismiss the Petition's challenge to the permit as moot.

### B. The EAB Would Have Had Jurisdiction Over The PSD Permit If It Had Been Timely Appealed (And If All Other Jurisdictional Requirements Had Been Satisfied)

Hypothetically, if a petitioner had appealed within 30 days of the issuance of the PSD Permit, and had participated in the permitting process and properly preserved the arguments for the appeal, then the Environmental Appeals Board would have jurisdiction over the appeal. The District issues Federal PSD Permits under its Delegation Agreement with EPA Region 9 in an integrated permitting system along with District Authorities to Construct.[8] When the final permit

[7] Furthermore, the issues raised in the Petition regarding the 2001 PSD Permit are not "capable of repetition, yet evading review" because to the extent that they ever arise again in future permitting, they will be fully reviewable in appeals of future permitting actions and will not "evade review".

[8] As noted above, this integrated permitting system was described in detail by the Board in its decision in the *Russell City* case, PSD Appeal No. 08-01.

documents are issued, the state-law Authority to Construct permit becomes appealable to the District's Hearing Board and then to the California courts, while the Federal PSD Permit becomes appealable to the EAB and then to the federal courts. The Board has entertained several appeals of Federal PSD Permits issued by the District over the years under this integrated system. (*See In re Russell City Energy Center*, PSD Appeal No. 08-01, 14 E.A.D. __ (July 29, 2008); *In re Metcalf Energy Center*, PSD Appeal Nos. 01-07 and 01-08 (Aug. 10, 2001), *aff'd*, *Santa Teresa Citizens Action Group v. EPA*, No. 01-71611 (9th Cir. Nov. 21, 2002).)

The *Metcalf* case is particularly instructive on this point, as the permit there was issued in the same time frame as the initial permit for the Gateway facility. The Metcalf permit was issued on May 4, 2001, and the appeal was pending until August 10, 2001, when the Board denied it. (*See Metcalf*, PSD Appeal Nos. 01-07 and 01-08, Slip. Op. at pp. 1, 45.) The District issued the permit for the Gateway facility on July 24, 2001, in the middle of this process. (*See* Petition at p. 6 and Exh. 1.) If the PSD permit for this facility had been appealed at that time, it would have joined the Metcalf case on the Board's docket and the Board would have had jurisdiction to adjudicate it (assuming of course that the Petitioner could have satisfied all of the threshold procedural requirements).

The District does note that the Board phrased its request for further briefing on this issue in terms of whether the EAB would have jurisdiction "over an appeal from the Authority to Construct" (Order at p. 6), and stated elsewhere that "it is questionable whether a final PSD permit decision was ever issued" (Order at p. 5). Obviously, the federal Environmental Appeals Board would not have jurisdiction over the state-law Authority to Construct, but that is not the question here because the permit at issue is the Federal PSD Permit the District issued under the integrated permitting process set up under the Delegation Agreement. Petitioner has attempted to create confusion over this issue by pointing out that the cover letter transmitting the permit states that it is the "Authority to Construct" but does not explicitly state that it is also the federal PSD Permit. (*See* Petition at p. 11.) The cover letter used that language because under the Delegation Agreement, "District permits issued in accordance with the provisions of Regulation

2-Rule 2 [*i.e.*, District Authorities to Construct] were deemed to meet the federal PSD permit requirements" and thus to be effective as federal PSD Permits. (Delegation Agreement, Crockett Decl. Exh. A, ¶ I.1.) Under this guidance in the Delegation Agreement, the District often referred to these integrated state/federal permits simply as an "Authority to Construct", even though they were intended for all practical and legal purposes to be effective as both an Authority to Construct under state law and a PSD Permit under federal law. The use of this shorthand in the permit transmittal letter does not change the legal effect of the District's action in issuing the permit, which was to issue both the state-law Authority to Construct and the Federal PSD Permit.

The fact that the District's permitting action included the Federal PSD permit as well as the District Authority to Construct is clear from references to the PSD requirements throughout the permitting record, even if the permit transmittal letter did not explicitly state that the integrated permit was being issued to serve as both. For example, when the District responded to the comments of Californians for Renewable Energy ("CARE") on the PDOC/Draft PSD Permit, it explicitly stated that it was not yet issuing the final PSD permit because the Endangered Species Act ("ESA") consultation was not complete. (*See* Letter from Ellen Garvey, BAAQMD, to Michael Boyd, CARE, February 6, 2001, Exh. D to Crockett Decl.) When EPA engaged in the ESA consultation, it expressly stated that the consultation was related to the issuance of the federal PSD Permit for the facility. (*See* Letter from Gerardo Rios, EPA Region 9, to Jan Knight US Fish & Wildlife Service, May 30, 2001, Exh E to Crockett Decl.) When the consultation was complete, EPA Region 9 wrote to the District to inform the District of that fact, and stated that "the District may issue a final PSD permit . . . in accordance with the PSD Delegation Agreement between EPA and BAAQMD." (Letter from Gerardo Rios, EPA Region 9, to Ellen Garvey, BAAQMD, July 12, 2001, Exh. F to Crockett Decl.) And when the District went ahead and did so, it expressly cited PSD requirements as a basis for many of the actual permit conditions that made up the integrated permitting document. (*See, e.g.*, PSD Permit, Exh. 1 to Petition (Conditions 14, 15, 20-24, 26, 27, 36, 45 & 46 referencing PSD as a basis).) The

semantic effect of the term used in the permit cover letter cannot change the legal effect of the issuance of the permit as an integrated state/federal permit as both a District Authority to Construct and a federal PSD Permit. The permit that the Board would have had jurisdiction to review here, if an appeal had been filed at the time, would have been the Federal PSD Permit, as was the case in the *Metcalf* proceeding.

But again, this is purely a hypothetical issue at this stage. The Petition in this case was not filed when the permit was issued, it was filed nearly eight years later and after the facility was constructed and commenced operating. As explained above, the Board cannot take jurisdiction over Petitioner's claims in the Section 124.19 permit appeal context under these circumstances. And even if the Petition's un-timeliness can be excused, the Board would still lack jurisdiction because the permit has expired and any issues of its validity are now moot. Put another way, since there is no dispute that the permit was invalid at least by the time construction ceased for over 18 months, there can be no reason to adjudicate whether it became invalid because it expired, or whether it never became valid in the first place because it failed to state "PSD" in the transmittal letter. The outcome is the same either way. The Board should not take jurisdiction of the Petition based on this moot issue.

### C. There Is No Other Jurisdictional Basis For This Appeal

As the Board notes in its Order, the only permitting action identified in the Petition was the initial permit issuance in 2001. (*See* Order at p. 4.) As explained above, the Board lacks jurisdiction over this permitting action because the Petition is untimely, and also because any such appeal is moot at this stage so long after the initial permit term expired. The Petition does not provide any other jurisdictional basis for this appeal.

The Petition does reference two other areas of permitting activity, however. Neither of these provides a jurisdictional basis for an appeal under 40 C.F.R. Section 124.19, but since Petitioner has raised them and may seek to assert them as a basis for jurisdiction the District addressed them here.

The first of these additional areas of permitting activity that Petitioner raises concerns the District's extensions of the Authority to Construct, which the Petition states did not extend the PSD Permit when it expired. (*See* Petition at pp. 9-10.) As noted above, the District was under the understanding that extensions of the Authority to Construct would be effective to extend the Federal PSD Permit as well based on the language of the Delegation Agreement between the District and EPA Region 9. (*See* Delegation Agreement, Crockett Decl. Exh. A, at ¶ I.1.) EPA Region 9 has now taken the position in hindsight that extensions of an Authority to Construct are not effective to extend a PSD Permit, notwithstanding the language in the PSD Delegation Agreement.[9] (*See* Crockett Dec'l Exh. C.) Given this recent guidance from EPA Region 9 regarding implementation of the District's delegated PSD authority, the District does not disagree with Petitioner to the extent he alleges that the renewals of the Authority to Construct were not effective to renew the Federal PSD Permit. As the parties are not now in disagreement on this point, there is no live controversy between them for this Board to adjudicate. Because there is no dispute on the issue of whether the initial PSD Permit was validly extended, the Petition should be dismissed as moot in this respect as well. (*See In re: Great Lakes Chemical Corp.*, 5 E.A.D. 395, 397 (EAB 1994) ("Because there is no longer any dispute [over the issue raised in the appeal], the Board denies review on the grounds that the issue is moot.").) Again, there would be no purpose to be served by adjudicating such an appeal, as there is no meaningful relief the Board could grant on this issue where the parties do not disagree that, based on Region 9's recent guidance, there were no effective extensions of the PSD Permit after it expired.

The other area of permitting activity that Petitioner raises concerns the revised permit that the project owner applied for in 2007 (*see* Petition at pp. 11-17), but which the District never issued because the application was withdrawn (*see* Crockett Decl. Exh. B). To the extent that Petitioner is attempting to appeal a permit that has not yet been issued, such a claim is not ripe

[9] Note that EPA Region 9 has given revised guidance with respect to the permit extension issue only. Region 9 has given no indication that it does not continue to believe that the original permit was issued as a PSD permit.

until the permitting agency has taken final action on the permit and there is a "final permit decision" within the language of 40 C.F.R. section 124.19(a) for the EAB to review. As the Board has held in similar circumstances where appeals have been filed before the permit is actually issued, the petition must be dismissed with respect to such claims. (*See In re City & County of San Francisco*, 4 E.A.D. 559, 574 (EAB 1993) ("[U]ntil such time as the Region makes a decision on the re-proposed permit, [the issues raised in the Petition] and the many sub-issues raised thereunder and arguments asserted in support thereof, are not yet ripe for review.").) The Petition presents the same situation here in challenging an amended permit that was never issued. It therefore must be dismissed on this issue as unripe because there is no final permit decision to adjudicate under Section 124.19.

Notably, Petitioner's appeal in this regard is similar to his most recent Petition to this Board regarding the proposed Russell City Energy Center (Docket No. PSD 08-07). In that case, Petitioner sought to challenge certain decisions regarding the proposed Russell City facility made by the California Energy Commission while the District was conducting further PSD permitting proceedings as directed by the EAB in its Remand Order in Docket No. PSD 08-01. Because there had not been any final action with respect to the PSD permit proceeding, the Board held that there was nothing yet to review and dismissed the appeal. (*See In re Russell City Energy Center*, PSD Appeal No. 08-07 (Nov. 25, 2008), slip. op. at p. 3 ("Since no PSD action within this Board's jurisdiction is being appealed, the review of the Petition is denied.").) Petitioner's current Petition is the same with respect to the never-issued PSD Permit amendment. Petitioner seeks to raise purported defects in the permitting proceeding in absence of any final agency action in that proceeding, and the Board should dismiss such claims until such time as there may be an actual PSD permitting action for the Board to review.

For all of these reasons, nothing in the Petition provides any ground for EAB jurisdiction under 40 C.F.R. Section 124.19.

## IV. THE APPROPRIATE VENUE TO ADDRESS THE CLAIMS RAISED IN THE PETITION AT THIS STAGE IS IN THE ENFORCEMENT CONTEXT, NOT IN THE PERMIT REVIEW CONTEXT.

This analysis of the jurisdictional questions raised by the Petition highlights the fact that the Petition presents, at most, a Clean Air Act enforcement matter, not a permitting issue for this Board to adjudicate under its authority in 40 C.F.R. Section 124.19. Fundamentally, the Petition claims that the Gateway Generating Station was constructed without a valid Federal PSD permit in violation of the PSD Provisions of the Clean Air Act (or alternatively that the facility is in violation of the conditions of its PSD Permit). To the extent that these claims have any merit, they are enforcement issues that must be addressed by Region 9 through a Clean Air Act enforcement action—a process that Region 9 has already begun. They do not challenge PSD permitting actions that the Environmental Appeals Board can or should adjudicate at this stage in the permit appeal context under 40 C.F.R. Section 124.19.

The Petition does of course devote much discussion to several of the PSD-permitting-related actions that have occurred over the long permitting history of the Gateway facility, but none of them presents a live permitting issue for this Board to adjudicate at this point, for the reasons discussed above. Once these purported bases for a permit appeals are seen for what they are—elements of the facility's permitting history, but nothing that presents a live controversy to be adjudicated in an appeal today—it becomes clear what the Petition really is: an attempt to get the EAB to take up Petitioner's claims that the facility has violated the PSD provisions of the Clean Air Act. But such claims must be addressed as Clean Air Act violations through the Clean Air Act enforcement process, and cannot be raised in a permit appeal brought under 40 C.F.R. section 124.19. (*See In re City of Fort Worth*, NPDES Appeal No. 95-8, 6 E.A.D. 392, 408 n. 21 (EAB 1996) (dismissing claim that facility was in violation of its permit, as opposed to challenge to condition of permit, because "if current permit conditions are being violated, such an issue is appropriately addressed through the Agency's enforcement process, and not through these permit issuance proceedings"), and additional cases cited therein.) The Board should therefore dismiss these PSD compliance issues that Petitioner is attempting to raise in this permit appeal

proceeding, and instead allow them to be addressed in the appropriate venue, which is through Region 9's enforcement action.

## V. CONCLUSION

For all of the foregoing reasons, the Bay Area Air Quality Management District respectfully submits that the Petition for Review should be dismissed for lack of jurisdiction.

Dated: June 22, 2009

Respectfully Submitted

BRIAN C. BUNGER, ESQ.
DISTRICT COUNSEL
BAY AREA AIR QUALITY
MANAGEMENT DISTRICT

By: Alexander G. Crockett Esq.
Assistant Counsel

## PROOF OF SERVICE

I, Charlene Forbush, declare as follows: I am over the age of 18, not a party to this action, and employed in the City and County of San Francisco, California, at 939 Ellis Street, San Francisco, CA, 94109. On the date set forth below, I served this document, "BAAQMD Brief on Jurisdictional Issues", by placing a copy of it in a sealed envelope, with First Class postage thereon fully paid, and depositing said envelope in the United States Mail at San Francisco, California, addressed to the person set forth below:

Mr. Rob Simpson
27126 Grandview Avenue
Hayward, CA 94542

David Farabee, Esq.
Pillsbury Winthrop Shaw Pittman LLP
50 Fremont Street
Post Office Box 7880
San Francisco, CA 94120-7880

Nancy Marvel, Esq., Regional Counsel
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, CA 94105

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct.

Executed on 30, 2009, at San Francisco, California.

Charlene Forbush

**BEFORE THE ENVIRONMENTAL APPEALS BOARD**
**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**WASHINGTON, D.C.**

| | | |
|---|---|---|
| In the matter of<br>Gateway Generating Station | )<br>)<br>)<br>)<br>) | PSD Appeal No. 09-02 |

**DECLARATION OF ALEXANDER G. CROCKETT, ESQ.,**
**IN SUPPORT OF BAAQMD BRIEF ON JURISDICTIONAL ISSUES**

I, Alexander G. Crockett, Esq., hereby declare as follows.

1. I am employed by the Bay Area Air Quality Management District ("District") as Assistant Counsel. I am the staff attorney with primary direct responsibility for the above-captioned matter, and generally for legal issues regarding permitting and enforcement with respect to the Gateway Generating Station. I make this Declaration in support of the District's Brief on Jurisdictional Issues being filed concurrently herewith. I have personal knowledge of the matters stated herein and know them to be true (or, where indicated, I am informed and believe that they are true), and I can testify truthfully and competently thereto.

2. Attached hereto as Exhibit A is a true and correct copy of an agreement between the District and EPA Region 9 regarding delegation of the Federal Prevention of Significant Deterioration ("PSD") permitting program in the San Francisco Bay Area, entitled *U.S. EPA – Bay Area Air Quality Management District Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21.*

3. Attached hereto as Exhibit B is a true and correct copy of a letter dated February 13, 2009, from Thomas Allen of Pacific Gas & Electric Co., to Brian Bateman of the District.

4. Attached hereto as Exhibit C is a true and correct copy of a letter dated May 21, 2009, from Brian C. Bunger, Esq., District Counsel, to Nancy Marvel, Esq., EPA Region 9 Regional Counsel.

5. Attached hereto as Exhibit D is a true and correct copy of a letter dated February 6, 2001, from Ms. Ellen Garvey, District Executive Officer/Air Pollution Control Officer, to Mr. Michael Boyd, President, Californians for Renewable Energy ("CARE").

6. Attached hereto as Exhibit E is a true and correct copy of a letter dated May 30, 2001, from Mr. Gerardo Rios, Acting Chief, Permits Office, EPA Region 9, to Mr. Jan Knight, Chief, Endangered Species Division, U.S. Fish & Wildlife Service.

7. Attached hereto as Exhibit F is a true and correct copy of a letter dated July 12, 2001, from Mr. Gerardo Rios, Acting Supervisor, Permits Office, EPA Region 9, to Ms. Ellen Garvey, District Executive Officer/Air Pollution Control Officer.

I declare under penalty of perjury under the laws of California that the foregoing is true and correct, and that this declaration was executed on June 22, 2009.

Alexander G. Crockett, Esq.

## PROOF OF SERVICE

I, Charlene Forbush, declare as follows: I am over the age of 18, not a party to this action, and employed in the City and County of San Francisco, California, at 939 Ellis Street, San Francisco, CA, 94109. On the date set forth below, I served this document, "Declaration of Alexander G. Crockett, Esq., in support of BAAQMD Brief on Jurisdictional Issues", by placing a copy of it in a sealed envelope, with First Class postage thereon fully paid, and depositing said envelope in the United States Mail at San Francisco, California, addressed to the person set forth below:

Mr. Rob Simpson
27126 Grandview Avenue
Hayward, CA 94542

David Farabee, Esq.
Pillsbury Winthrop Shaw Pittman LLP
50 Fremont Street
Post Office Box 7880
San Francisco, CA 94120-7880

Nancy Marvel, Esq., Regional Counsel
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, CA 94105

I declare under penalty of perjury, under the laws of the State of California, that the foregoing is true and correct.

Executed on 30, 2009, at San Francisco, California.

Charlene Forbush

# EXHIBIT A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

FEB 04 2008

Mr. Jack Broadbent
Air Pollution Control Officer
Bay Area AQMD
939 Ellis Street
San Francisco, CA 94109-7799

RE: Amended PSD Delegation Agreement

Dear ~~Mr.~~ Jack Broadbent:

EPA appreciates the efforts of your staff to work with us in amending your Prevention of Significant Deterioration (PSD) Delegation agreement between the District and EPA. Under the amended delegation agreement, the District is now primarily responsible for issuing and modifying PSD permits. EPA remains available to assist the District in any applicability or implementation issues. I am pleased to enclose a signed copy of the revised PSD delegation agreement. The agreement is effective immediately.

Please contact Laura Yannayon at (415) 972-3534 if you have any other questions related to this matter.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosure

cc: Brian C. Bunger, Bay Area Air Quality Management District, w/enclosure
James Goldstene, Executive Officer, California Air Resources Board w/enclosure

Printed on Recycled Paper

**U.S. EPA - Bay Area Air Quality Management District**

**Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21**

The undersigned, on behalf of the Bay Area Air Quality Management District (District) and the United States Environmental Protection Agency (EPA), hereby agree to the partial delegation of authority to issue Prevention of Significant Deterioration (PSD) initial permits and to modify existing PSD permits, subject to the terms and conditions of this Agreement. This partial delegation is executed pursuant to 40 CFR 52.21(u), Delegation of Authority.

## I. Background Recitals

1. On April 23, 1986, EPA delegated authority to implement the federal PSD regulations at 40 CFR 52.21 to the District. This delegation was based on EPA's determination that the PSD portion of District Regulation 2 – Rule 2 (Readopted and Renumbered July 17, 1991, amended June 15, 1994) generally met the requirements of 40 CFR 52.21; therefore District permits issued in accordance with the provisions of Regulation 2 – Rule 2 were deemed to meet the federal PSD permit requirements pursuant to the provisions of the delegation agreement.
2. On December 31, 2002, EPA finalized revisions to the regulations at 40 CFR 52.21, which became effective on March 3, 2003. See 67 FR 80186. After discussions with the California Air Resources Board and the District, EPA informed the District that it would need to adopt revisions to Regulation 2 – Rule 2 to address the recent PSD revisions and continue to implement the federal PSD program pursuant to 40 CFR 52.21. Accordingly, on March 3, 2003, EPA withdrew the delegation of federal PSD authority from the District. See 68 FR 19371 (April 21, 2003).
3. On June 24, 2005, the District of Columbia Court of Appeals vacated two provisions of the revised federal PSD regulations related to Clean Units and Pollution Control Projects. The provisions upheld by the Court provide new additional calculation methodologies for determining if a proposed project will result in a major modification and the application

of a Plantwide Applicability Limit (PAL). On June 13, 2007, EPA issued a direct final rule revising the federal PSD regulations to remove the vacated portions.

## II. Scope of Partial Delegation

1. The provisions upheld by the court (additional calculation methodologies and PALs) are not specifically addressed by Regulation 2 – Rule 2. Therefore, this partial delegation of authority to issue and modify PSD permits does not delegate authority to the District to modify PSD permits when the applicant seeks to use the additional calculation methodologies promulgated in 40 CFR 52.21 but not set forth in Regulation 2 – Rule 2 and does not delegate authority to issue new or modified PSD permits based on PALs.
2. For all applications for new or modified PSD permits other than those set forth in paragraph 1 above, the existing District regulations continue to generally meet the requirements of 40 CFR 52.21 for issuing PSD permits; therefore District permits issued in accordance with the provisions of Regulation 2 – Rule 2 shall be deemed to meet federal PSD permit requirements pursuant to the provisions of this delegation agreement.

## III. Applicability

1. EPA and the District have agreed to this partial delegation of PSD authority to allow the District to issue initial and modified PSD permits, except for modifications seeking to determine PSD applicability based on the additional calculation methodologies set forth in 40 CFR 52.21 and new or modified PSD permits seeking PALs. (Modifications include Administrative Amendments, Major Modifications, and non-Major Modifications.)
2. Pursuant to this partial delegation agreement, the District shall have primary responsibility for issuing all new and modified PSD permit(s).
3. The authority to issue a PSD permit containing a PAL is not delegated to the District as part of this delegation agreement. If any facility subject to this agreement requests a permit modification to incorporate conditions for a PAL, as provided in 40 CFR 52.21(aa), EPA shall process the application and issue the final PAL permit for the modification.

4. If any source seeks a PSD permit modification based on determining applicability with the additional calculation methodologies set forth in 40 CFR 52.21 (as revised in 2002), EPA shall issue the PSD permit.

5. This partial delegation of PSD authority becomes effective upon the date of the signatures of both parties to this Agreement.

## IV. General Delegation Conditions

1. The District shall issue PSD permits under this partial delegation Agreement in accordance with the PSD requirements of the District's Regulation 2 – Rule 2 and 40 CFR 52.21, as amended on December 31, 2002; except as provided in subsection III.

2. This partial delegation may be amended at any time by the formal written agreement of both the District and the EPA, including amendments to add, change, or remove terms or conditions of this Agreement.

3. EPA may review the PSD permit(s) issued by the District to ensure that the District's implementation of this delegation Agreement is consistent with federal PSD regulations for major sources and major modifications (40 CFR 52.21).

4. If the EPA determines that the District is not implementing or enforcing the PSD program in accordance with the terms and conditions of this partial delegation agreement, the requirements of Regulation 2 – Rule 2, 40 CFR 52.21, 40 CFR 124 or the Clean Air Act, this partial delegation agreement may be revoked in whole or in part. Any such revocation shall be effective as of the date specified in a Notice of Revocation to the District.

5. If the District determines that issuing a PSD permit in accordance with the terms and conditions of this agreement, the requirements of Regulation 2 – Rule 2, 40 CFR 52.21, 40 CFR 124 or the Clean Air Act conflicts with State or local law, or exceeds the District's authority or resources to fully and satisfactorily carry out such responsibilities, the District after consultation with EPA, may remand administration of these permits to EPA. Any such remand shall be effective as of the date specified in a Notice of Remand to EPA.

6. The permit appeal provisions of 40 CFR 124, including subpart C thereof, pertaining to the Environmental Appeals Board (EAB), shall apply to all federal PSD permitting action appeals to the EAB for permits issued by the District under this partial delegation agreement. For purposes of implementing the federal permit appeal provisions under this partial delegation, if there is a public comment requesting a change in a draft preliminary determination or draft permit conditions, the final permit issued by the District shall contain a statement that for federal PSD purposes and in accordance with 40 CFR 124.15 and 124.19, (1) the effective date of the permit shall be 30 days after the date of the final decision by the District to issue, modify, or revoke and reissue the permit; and (2) if an appeal is made to the EAB, the effective date of the permit shall be suspended until such time as the appeal is resolved. Failure by the District to comply with the terms of this paragraph shall render the subject permit invalid for PSD purposes.

## V. Communication Between EPA and the District

The District and EPA will use the following communication procedures:

1. The District will forward to EPA copies of (1) the findings related to the PSD application, (2) the justification for the District's preliminary determination, (3) the draft permit and (4) all public notices required by 40 CFR 124. Such copies shall be provided at or prior to the beginning of the public comment period for each PSD preliminary determination. EPA will provide comments to the District as soon as possible prior to the close of the public comment period.
2. The District will forward to EPA copies of the final action for each PSD permit application at the time of issuance, as well as a summary of public comments and, upon request by EPA, copies of substantive public comments.
3. The District will send to EPA a copy of all PSD non-applicability determinations that utilize netting. All such determinations must be accompanied by a written justification.

## VI. EPA Policies Applicable to PSD Review

1. EPA is responsible for the issuance of PSD permits on Indian Lands, under Sections 110 and 301 of the Clean Air Act and for those situations set forth in Section III above. This

agreement in no way grants or delegates any authority under the Clean Air Act on Indian Lands to the District.

2. All PSD BACT determinations are required to perform a "top-down" BACT analyses. EPA will consider as deficient any BACT determination that does not begin with the most stringent control options available for that source category.

3. The District must consult with the appropriate Federal, State and local land use agencies prior to issuance of a PSD permit preliminary determination. For the purposes of the Endangered Species Act (ESA), the District shall:

   a. Notify the appropriate Federal Land Manager (FLM) within 30 days of receipt of a PSD permit application. If the proposed project will impact a Class I area, notify the appropriate Federal Land Manager (FLM) no later than 60 days prior to issuing a public notice for the project.

   b. Notify the Fish and Wildlife Service (FWS) and EPA when a submitted PSD permit application has been deemed complete, in order to assist EPA in caring out its non-delegable responsibilities under Section 7 of the ESA (PL 97-304).

   c. Notify applicants of the potential need for consultation between EPA and FWS if an endangered species may be affected by the project.

   d. Refrain from issuing a final PSD permit unless FWS has determined that the proposed project will not adversely affect any endangered species.

## VII. Permits

1. The District shall follow EPA guidance on any matter involving the interpretation of Sections 160-169 of the Clean Air Act or 40 CFR 52.21, relating to applicability determinations, PSD permit issuance and enforcement.

2. The District will at no time grant any waiver to the PSD permit requirements.

3. Authorities to Construct must include appropriate provisions to ensure permit enforceability. Permit conditions shall, at a minimum, contain reporting requirements on initiation of construction, start-up, and source testing (where applicable).

4. When any conditions of a PSD permit are incorporated into a Title V permit, the District shall clearly identify PSD as the basis for those conditions.

5. The primary responsibility for the administration and enforcement of the following EPA-issued permits is delegated to the District:

| Facility | EPA File Number | Permit Issuance Date |
|---|---|---|
| Calpine Gilroy Cogen | SFB 84-04 | August 1, 1985 |
| Cardinal Cogen | SFB 82-04 | June 27, 1983 |
| Crockett Cogen | SFB 82-05 | February 9, 1983 |
| IBM Corporation | SFB 82-01 | June 9, 1982 |
| Martinez Cogen Limited Partnership | SFB 83-01 | December 13, 1983 |
| Tosco Corporation | SFB 78-07 | December 18, 1978 |
| Tosco SF Area Refinery at Rodeo | SFB 85-03 | March 3, 1986 |

District-issued modifications to these permits which meet the requirements of 40 CFR 52.21 will be considered valid by EPA. The District shall issue any permit modifications to the above listed sources pursuant to this agreement and using District Regulation 2 – Rule 2, which incorporates the requirements of 40 CFR 52.21.

## VIII. Permit Enforcement

1. The primary responsibility for enforcement of the PSD regulations rests with the District. The District will enforce the provisions of the PSD program except in those cases where District rules or policy are more stringent. In that case, the District may elect to implement the more stringent requirements.

2. Nothing in this partial delegation agreement shall prohibit EPA from enforcing the PSD provisions of the Clean Air Act, 40 CFR 52.21 or any PSD permit issued by the District pursuant to this agreement.

3. In the event that the District is unwilling or unable to enforce a provision of this partial delegation agreement with respect to a source subject to the PSD regulations, the District will immediately notify the Air Division Director. Failure to notify the

Air Division Director does not preclude EPA from exercising its enforcement authority.

Jan 29, 2008
Date

Jack P. Broadbent
Executive Officer/APCO
Bay Area Air Quality Management District

Feb. 6, 2008
Date

Deborah Jordan
Director, Air Division
U.S. EPA, Region IX

# EXHIBIT B

Pacific Gas and Electric Company®

Mailing Address:
Pacific Gas & Electric Company
Gateway Generating Station
3225 Wilbur Ave.
Antioch, CA 94509
(925) 522-7801

RECEIVED
FEB 17 AM 10:43
BAY AREA AIR QUALITY MANAGEMENT DISTRICT

February 13, 2009

Brian Bateman
Director of Engineering
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Application for Modifications to the Authority to Construct
Gateway Generating Station—Plant No. 18143, Application No. 17182

Dear Mr. Bateman:

PG&E hereby withdraws Application No. 17182, the application for modifications to the Authority to Construct for the Gateway Generating Station (GGS), which was filed with the District in December 2007. As we have discussed with you, the principal reason for requesting the permit modifications was because we believed that the original conditions governing commissioning and startups were overly stringent and could not be complied with. In our application we had requested changes to these conditions that would have increased some emissions limits and extended some time periods related to commissioning and startups. However, GGS has completed commissioning in compliance with the existing conditions, so no revisions are needed for commissioning-related conditions. Further, GGS has completed several warm and hot startups and two complete cold startups. Based on the data collected during these startups, we now believe we can comply with the existing startup conditions. As a result, we no longer believe the amendments originally requested in our December 2007 application are necessary.

We appreciate the assistance you and your staff have provided during the permit review. If you have any questions regarding this request to withdraw the application, please do not hesitate to call me or Gary Rubenstein of Sierra Research at (916) 444-6666.

Sincerely,

Thomas Allen
Project Manager

cc: Brian Lusher, BAAQMD Permit Services
Andrea Grenier, Grenier & Associates
Scott Galati, Galati Blek
Gary Rubenstein, Sierra Research

# EXHIBIT C

FILE COPY

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT
SINCE 1955

May 21, 2009

**BY FAX (415/947-3571)**
**AND FIRST CLASS MAIL**

Nancy Marvel, Esq.
Regional Counsel
United States Environmental Protection Agency
Region IX
75 Hawthorne Street
San Francisco, CA 94108

Re: Potential PSD Non-Compliance – Gateway Generating Station

Dear Ms. Marvel:

I am writing to confirm the understanding of the Bay Area Air Quality Management District ("District") regarding EPA Region 9's interpretation of the Federal PSD Permit status of the Gateway Generating Station based on discussions between District and Region 9 representatives over the past several weeks. This letter is to memorialize the District's understanding in writing, and also to ensure that the District has satisfied its obligation under Paragraph VIII.3. of the PSD Delegation Agreement between our agencies, which requires that the District notify EPA Region 9 in the event that there is potential non-compliance with Federal PSD requirements over which the District does not have enforcement jurisdiction.

As has been made clear in recent discussions, the District issued a Federal PSD Permit for the Gateway facility in 2001, in conjunction with a District Authority to Construct issued under District regulations. The District issued the Federal PSD Permit on behalf of EPA Region 9, pursuant to the Delegation Agreement between the two agencies. The project owner subsequently began construction on the facility, but then ceased construction for more than 18 months, which required that the PSD permit be extended under 40 C.F.R. section 52.21(r)(2). The Air District issued several extensions of the District Authority to Construct over the next several years, and intended that these extensions would be effective to extend the Federal PSD permit as well. The District's

understanding that the Authority to Construct extensions would also extend the Federal PSD Permit was based on the provision in the Delegation Agreement establishing that permits issued pursuant to District regulations are deemed to meet the Federal PSD permit requirements. (*See,* Delegation Agreement, ¶ I.1.) In recent discussions, however, EPA Region 9 staff have informed District staff that they do not now consider the Authority to Construct extensions to have been effective to extend the Federal PSD Permit, notwithstanding the provisions of the Delegation Agreement. As a result of this interpretation, it appears that the Federal PSD Permit for the facility expired and was not extended or renewed.

After a cessation of work on the project for several years, the current project owner restarted construction and completed the facility, and has now commenced operation. The project owner has stated in discussions with District and EPA Region 9 staff that it believed that the Federal PSD Permit as initially issued had been duly extended and was still valid when the facility was constructed. EPA's recent clarification of its interpretation of the status of the Federal PSD Permit conflicts with this view, however, and suggests that the Federal PSD Permit had expired and was no longer valid when construction was restarted and completed. Construction of the facility without a current Federal PSD Permit would be a violation of the Clean Air Act's PSD provisions. To the extent that this situation presents a non-compliance situation with respect to the PSD requirements, the District is obligated under Paragraph VIII.3. of the Delegation Agreement to refer any enforcement action to EPA Region 9 as the federal agency responsible for enforcing the Federal Clean Air Act in the Bay Area. This letter is to document the District's compliance with that provision of the Delegation Agreement.

Please give me a call at the number listed above if you would like to discuss any of the foregoing, or alternatively have your staff who have been working on these matters contact Alexander Crockett of my staff at (415) 749-4732.

Sincerely,

Brian C. Bunger, Esq.
District Counsel

cc: Alexander Crockett, Esq., BAAQMD
Ann Lyons, Esq., EPA Region 9
David Farabee, Esq., Pillsbury Winthrop LLP

TRANSMISSION VERIFICATION REPORT

TIME : 05/21/2009 15:55
NAME : BAAQMD COUNSEL
FAX : 4157495103
TEL : 4157495103
SER.# : BROE5J279710

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| DATE,TIME | 05/21 15:54 |
| FAX NO./NAME | 914159473571 |
| DURATION | 00:01:00 |
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| RESULT | OK |
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BAY AREA AIR QUALITY MANAGEMENT DISTRICT

DISTRICT COUNSEL'S OFFICE
939 ELLIS STREET
SAN FRANCISCO, CA 94109
TEL. (415) 749-4920
FAX: (415) 749-5103

# *FACSIMILE TRANSMITTAL SHEET*

DATE: 5/21/2009

FROM: Alexander Crockett, Assistant Counsel

TO: Nancy Matvel, Esq.
Regional Counsel

FAX: **(415) 947-3571**

COMPANY/FIRM: US EPA, Region IX

PHONE NUMBER:

REFERENCE: Gateway Generating Station

TOTAL NO. OF PAGES INCLUDING COVER: 3

SUBJECT: *Potential PSD Non-Compliance*

HANDLING:
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☐ URGENT ☐ FOR REVIEW ☐ PLEASE COMMENT ☐ PLEASE REPLY ☐ PER YOUR REQUEST

NOTES/COMMENTS:

TRANSMISSION VERIFICATION REPORT

TIME : 05/21/2009 15:53
NAME : BAAQMD COUNSEL
FAX : 4157495103
TEL : 4157495103
SER.# : BROE5J279710

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TEL. (415) 749-4920
FAX: (415) 749-5103


# *FACSIMILE TRANSMITTAL SHEET*

DATE: 5/21/2009

FROM: Alexander Crockett, Assistant Counsel

TO: Nancy Marvel, Esq.
Regional Counsel

FAX: **(415) 947-3571**

COMPANY/FIRM: US EPA, Region IX

PHONE NUMBER:

REFERENCE: Gateway Generating Station

TOTAL NO. OF PAGES INCLUDING COVER: 3

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NOTES/COMMENTS:

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

DISTRICT COUNSEL'S OFFICE
939 ELLIS STREET
SAN FRANCISCO, CA 94109
TEL. (415) 749-4920
FAX: (415) 749-5103

# *FACSIMILE TRANSMITTAL SHEET*

DATE: 5/21/2009

FROM: Alexander Crockett, Assistant Counsel

TO: Nancy Marvel, Esq.
Regional Counsel

FAX: **(415) 947-3571**

COMPANY/FIRM: US EPA, Region IX

PHONE NUMBER:

REFERENCE: Gateway Generating Station

TOTAL NO. OF PAGES INCLUDING COVER: 3

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NOTES/COMMENTS:

**IMPORTANT/CONFIDENTIAL:** This communication is intended only for the use of the individual or entity to which it is addressed, and may contain information that is privileged, confidential and exempt from disclosure under applicable law. If you read this communication and you are not the intended recipient or the employee or agent responsible for delivering the message to the intended recipient, you are hereby notified that any dissemination, distribution, or copying of this information is strictly prohibited. If you have received this communication in error, please notify us immediately by telephone. Thank you.

# EXHIBIT D

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ALAMEDA COUNTY
Roberta Cooper
Scott Haggerty
(Vice-Chairperson)
Nate Miley
Shelia Young

CONTRA COSTA COUNTY
Mark DeSaulnier
Mark Ross
Gayle Uilkema

MARIN COUNTY
Harold C. Brown, Jr.

NAPA COUNTY
Brad Wagenknecht

SAN FRANCISCO COUNTY
Amos Brown
Michael Yaki

SAN MATEO COUNTY
Jerry Hill
Marland Townsend
(Secretary)

SANTA CLARA COUNTY
Randy Attaway
(Chairperson)
Liz Kniss
Julia Miller
Dena Mossar

SOLANO COUNTY
William Carroll

SONOMA COUNTY
Tim Smith
Pamela Torliatt

Ellen Garvey
Executive Officer/
Air Pollution Control Officer

February 6, 2001

Mr. Michael Boyd
President, CARE
821 Lakeknoll Drive
Sunnyvale, CA 94809

Re: Contra Costa Power Plant-Unit 8
Southern Energy Delta, LLC.
BAAQMD Application 1000

Dear Mr. Boyd:

Thank you for your comments regarding the Preliminary Determination of Compliance (PDOC) for the Contra Costa Power Plant-Unit 8 (CCPP-Unit 8). After careful consideration of those comments, we offer the following responses. A copy of the Final Determination of Compliance (FDOC) is enclosed. Please be advised that the FDOC does **not** constitute a Final PSD Permit under 40 CFR 52.21 since the United States Environmental Protection Agency (US EPA) is currently involved in a consultation with the U.S. Fish and Wildlife Service (USFWS) pursuant to Section 7 of the Endangered Species Act. The consultation concerns the potential impacts of the Contra Costa Power Plant-Unit 8 on federally protected species and will be completed when the USFWS issues their biological opinion on the potential impacts of the CCPP-Unit 8. The District will issue the Final PSD Permit after the Section 7 consultation process is completed and US EPA has determined that the issuance of the permit will be consistent with US EPA's obligations under the Endangered Species Act. Accordingly, the permit conditions in this FDOC are not final at this time. The Final PSD Permit may contain revised terms and permit conditions necessary to insure compliance with the requirements of the Endangered Species Act.

Comment II: The PDOC does not include a top-down BACT analysis.

Response: The FDOC includes a top-down BACT analysis that considers $SCONO_x$ and SCR as control technologies for $NO_x$. The analysis, which was conducted in accordance with the procedures described in EPA's 1990 Draft New Source Review Workshop Manual, considers the collateral impacts associated with $SCONO_x$ and SCR.

Comment III: A $NO_x$ emission limit of 2.5 ppmvd is not BACT.

Response: EPA Region IX, the ARB, SCAQMD, and the BAAQMD have all determined that BACT for $NO_x$ is an emission limitation of 2.5 ppmvd @ 15% $O_2$

averaged over one hour or 2.0 ppmvd @ 15% $O_2$, averaged over 3 hours.

It should be noted that Table 1, Cost-Effectiveness Analysis for SCONOx, in the CARE comments, is incorrect since it uses the cost for one gas turbine and the emissions for two gas turbines. The effect, of course, is to reduce the cost effectiveness by a factor of two.

Comment IV: BACT has not been required for CO. CO itself is an ozone precursor.

Response: The District is unaware of any commercial installations that have consistently operated at CO levels of less than 10 ppm while meeting a NOx level of 2.5 ppm. Levels authorized in EPA's PSD permit for Sutter are not relevant to BACT until the facility has been constructed and the level successfully achieved. The District has reviewed the CARB BACT clearinghouse, and none of the entries for turbines with NOx levels $\leq$ 2.5 ppm and CO levels < 10 ppm have been built. The applicant's proposed CO level of 6 ppm complies with BACT. The discussion in the FDOC will be expanded to include this information.

District regulations do not require a permit applicant to determine the impact of CO emissions on the formation of tropospheric ozone. The regulations require only that the release of CO from a facility does not cause a violation of all CO ambient air quality standards. The comment from CARE is also misleading. It is misleading because, contrary to CARE's assertion that 0.1 "represents the most conservative factor for assessing the relative ozone formation potential of CO emissions," basing the equivalency on propane is the least conservative factor since VOC emissions are as a whole, more reactive than propane.

Comment V: The POC limit of 2 ppmvd @ 15% $O_2$ is not BACT

Response: Based upon current available data, lower levels than 2 ppmvd have not been achieved in practice. The planned POC limit for this facility will be 2 ppmvd @ 15% $O_2$ one hour average. This is more stringent than the District and ARB BACT determination of 2 ppmvd POC @ 15% $O_2$ averaged over 3 hours that was established for the Delta Energy Center.

Comment VI: Start-up and shutdown emissions are improperly permitted since BACT was not required for start-up and shutdown. Gas turbine start-up and shutdown emission rates are inconsistent with vendor data.

Response: The District's method of limiting startup and shutdown emissions by using CEM data and source test correlation is the same as what has been used for the last three powerplants that the District approved. While we agree there can be problems that arise due to instrument ranges or response times the CEM instruments will be required to have sufficient scale ranges to monitor startups and shutdowns. Care will also be taken to insure that response times are rapid and equal, as far as possible. The emissions of unmonitored pollutants (those not on the CEM) will be calculated in the source testing program and correlated to the CEM and other monitored data. The District favors this CEM based approach because it can account for emission variations due to equipment deterioration or unforeseen process conditions. In addition, this method gives the applicant greater operating flexibility and is consistent with recent permits issued by the District.

It should be noted that the Startup/Shutdown emission table in this section of CARE's comment is incorrect because the last line of the table, labeled CCPP, is in fact emissions for the Metcalf Energy Center. The emissions for CCPP-Unit 8 do not appear in this table. In addition, this table is said to

be for Westinghouse 501F machines while CCPP-Unit 8 will use General Electric Frame 7FA machines.

Comment VII: $PM_{10}$ emissions are improperly estimated and permitted.

Response: The source tests that the PDOC emissions are based on tests that include both the front and back half (filterable and condensable) catch of particulate collection train.

Annual source testing of the Crockett Cogeneration gas turbine from 1996 through 1999 has shown front-end (filterable) $PM_{10}$ emission rates ranging from 0.8 lb./hr to 4.8 lb./hr for full load gas turbine operation with duct burner firing. If these emission rates are doubled to account for back-half (condensable) particulate matter; they show that the worst-case estimate of 13 pounds per hour is sufficiently conservative.

As far as a CEM to monitor $PM_{10}$ emissions, the District knows of no operational system that can monitor particulate emissions at the low levels produced by complete natural gas combustion. If this facility was burning solid waste or coal a $PM_{10}$ CEM might be practical but it is not considered feasible at the low levels this facility will operate at.

The CARE comment states that the cooling towers were incorrectly modeled as a series of point sources, rather than as volume sources in the ISC3 model runs. CARE then incorrectly states that the maximum 24-hour $PM_{10}$ impact from the facility was 8 mg/m3. The maximum 24-hour $PM_{10}$ impact from the project, as presented in the PDOC, was 4.6 mg/m3, not 8 mg/m3.

The Guideline on Air Quality Models, Appendix W to Part 51 of 40 CFR, Chapter I, states that volume sources are collections of a multitude of minor sources with individually small emissions that are impractical to consider as separate point or line sources. It continues by stating that volume sources are most commonly used for modeling elevated area sources, where there is no vertical component to the release. It is stated in the EPA ISC3 user manual that volume source algorithms are used to model releases from a variety of industrial sources, such as building roof monitors, multiple vents, and conveyor belts. The users manual continues on to say that the algorithms for volume sources cannot consider building downwash, whereas building downwash is considered for sources modeled as point sources.

Building downwash can, and often does, have a major influence on the air quality impact of a source and should always be considered. Because the characteristics of the cooling tower emissions are not of the nature of the volume sources as defined in the EPA documents, modeling the cooling tower as a series of point sources is the acceptable, and preferred, methodology for determining the impact from a cooling tower.

Comment VIII: The PDOC does not accurately assess the health risks of CCPP-Unit 8. The emission factors used for various compounds are too low since they do not reflect partial load operation or the use of dry-low $NO_x$ combustors. The acrolein emission factor improperly relies on CARB Method 430.

Response: The Calpine turbine in Pasadena Texas, which employs dry-low NOx combustors, was recently tested for acrolein, formaldehyde, and acetaldehyde at minimum load to address these concerns. In recognition of ARB's advisory regarding the use of Method 430 to measure acrolein,

EPA method TO-14 was used to measure acrolein. The results of the source tests show that the CATEF emission factors utilized to calculate the emission rates used in the health risk assessment were sufficiently conservative to assess the health impacts of the CCPP-Unit 8.

It should be further noted that footnote 67 in this section of CARE's comments is for the Metcalf Energy Center and refers to tables that are not in the CCPP-Unit 8 PDOC.

Comment IX: Contemporaneous Offsets should be considered. The PSD should not be issued prior to issuance of a biological opinion from the US Fish and Wildlife Service.

Response: Contemporaneous offsets for this facility would require shutting down the two existing units with a resulting loss of 690 MW of generating capacity (more than the 530 MW Unit 8 will add). After the NOx controls are retrofit (installation of SCR) as required by Regulation 9-11, the existing units will have a $NO_x$ emission level close to gas turbine BACT. The retrofit $NO_x$ levels will be 3.3 ppmvd @ 15% $O_2$ (10 ppmvd @ 3% $O_2$ per regulation 9-11). In addition, the District does not have the authority to require the applicant to use contemporaneous offsets.

As stated in the first paragraph of this letter, issuance of the FDOC does not constitute issuance of the PSD. The PSD will not be issued until issuance of a biological opinion from the US Fish and Wildlife Service.

If you have any questions, please contact, Dick Wocasek, Air Quality Engineer at (415) 749-4984.

Sincerely,

Ellen Garvey
Executive Officer/Air Pollution Control Officer

EG:frw
Enclosure

# EXHIBIT E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, California 94105-3901

30 May 2001

Ms. Jan Knight
Chief, Endangered Species Division
U.S. Fish and Wildlife Service
2800 Cottage Way, Suite W2605
Sacramento, California 95825-3901

Re: Request for Concurrence with EPA Finding of No Likely Adverse Effect under Section 7 of the ESA for Modification to Contra Costa Power Plant, Antioch, California

Dear Ms. Knight:

By this letter, the U.S. Environmental Protection Agency, Region 9 ("EPA") seeks to conclude informal consultation under Section 7 of the Endangered Species Act ("ESA") between EPA and the U.S. Fish and Wildlife Service ("FWS" or "Service") concerning the Contra Costa Power Plant Project (the "Project"). The Project involves a modification at an existing power plant to add a 530 MW natural gas-fired combined cycle combustion turbine (the "Turbine") at the existing Contra Costa Power Plant. Mirant Delta, LLC ("Mirant") has applied to the Bay Area Air Quality Management District ("BAAQMD") for a federal Prevention of Significant Deterioration ("PSD") permit for the Project, as required by Part C of the Clean Air Act and regulations at 40 C.F.R. § 52.21. Background information on the PSD program and more detailed information regarding the Project and this consultation are included below.

*Background on PSD Program*

Region 9 is responsible for complying with ESA Section 7 requirements with respect to federal PSD permitting. In some instances, EPA has delegated its PSD permitting authority to a state agency or air district pursuant to the PSD regulation at 40 C.F.R. § 52.21(u). In such instances, issuance of a federal PSD permit by a state agency or air district in EPA's stead is considered a federal action that may be subject to ESA requirements. (A "Delegation Agreement" establishes the roles and responsibilities for EPA and the State delegated to administer the PSD program and issue federal PSD permits in EPA's stead.)

A PSD permit for the Project is required for the modification to the existing power plant (i.e., installation of the Turbine). EPA has determined that issuance of the federal PSD permit for the Project is a federal action that may affect listed species or habitat through its construction or operation, thereby triggering ESA Section 7. Final action on this PSD permit may not occur

until EPA has determined that permit issuance will be consistent with the substantive and procedural requirements of the ESA.

*Informal Consultation and Request for Concurrence under Section 7 of the ESA*

EPA has been engaged in informal consultation with your office regarding the Project. We understand that you have been forwarded a copy of the California Energy Commission's Final Staff Assessment for the Project, which evaluates the environmental effects of the Project, including effects on listed species and habitat. In addition, as you are aware, Mirant previously submitted to the Service an application for an ESA Section 10 permit concerning the existing Contra Costa Power Plant. In this context, Mirant has prepared documents providing an analysis of the effects of the Contra Costa Power Plant on listed species and critical habitat, which were compiled as part of the ESA Section 10 permit application. Since EPA understands that your office already has copies of these documents, we are not forwarding them to you with this letter.

Mirant has discussed with the Service the potential impacts to species/habitat related to the Contra Costa Power Plant. The Service has identified the existing cooling water intake system at the facility as a concern, due to the potential for impingement and entrainment of the following listed threatened species: Delta smelt (*Hypomesus transpacificus)* and the Sacramento splittail (*Pogonichthys macrolepidotus*). The following listed threatened species under the National Marine Fisheries Service ("NMFS") jurisdiction also may be affected by the existing cooling water intake system: Central Valley ESU spring-run and winter-run chinook salmon (*Oncorhynchus tshawytscha*) and the Central Valley ESU Steelhead (*Oncorhynchus mykiss).* In addition, the following species are identified as occurring near the Project area but not likely to be adversely affected by the Project: San Joaquin harvest mouse (*Reithrodontomys raviventris*), California least tern (*Sterna antillarum browni*), Sort bird's-beak (*Cordylanthus mollis ssp. mollis*), Lange's metalmark butterfly (*Apdemia mormo langei*), Contra Costa Wallflower (*Erysimum capitatum angustatum*), Antioch Dunes evening Primrose (*Oenothera deltoids howellii*), all of which are listed endangered species.

Mirant has agreed to take measures that would avoid or minimize the effects associated with the power plant, namely the installation of an Aquatic Filter Barrier to address potential impacts from the cooling water intake at the existing facility. Mirant has applied for a permit from the United States Army Corps of Engineers ("COE") for installation of the Aquatic Filter Barrier on the cooling water intake system at the Contra Costa Power Plant. By letter dated April 19, 2001, the COE requested consultation under ESA Section 7 concerning its permit action for the Aquatic Filter Barrier. Since the COE has requested consultation on a matter that specifically addresses the cooling water intake system, the FWS and NMFS will have the opportunity to address any impacts of this intake system to species or habitat through COE's ESA Section 7 consultation.

EPA has discussed with the FWS potential effects associated with PSD permit issuance for the Project. Per a discussion between Pamela Schultz (Office of Regional Counsel, EPA, Region 9), Roger Kohn (Air Division, EPA, Region 9) and Michael Thabault (FWS) on March 30, 2001, the FWS noted that its only concern with respect to the Contra Costa Power Plant was related to impacts on listed and threatened species due to the cooling water intake system.

Apart from potential impacts associated with the existing cooling water intake system, EPA believes that there are no likely adverse effects to species or habitat resulting from the addition of the new Turbine to the Contra Costa Power Plant. As noted above, the COE has requested consultation with respect to its federal permit for installation of the Aquatic Filter Barrier at the cooling water intake system. EPA believes that COE's federal action is more directly related to the area of concern (i.e., effects of cooling water intake) than EPA's air permitting action and defers to COE and the outcome of COE's Section 7 consultation to address any potential impacts associated with the cooling water intake. With respect to EPA's air permitting matter, EPA finds that, in all other regards, the Project is not likely to adversely affect listed species or critical habitat, in accordance with 50 C.F.R. §§ 402.13 and 402.14(b). I am writing to request written concurrence from the Service with this finding.

If you have any questions regarding this request, please contact Roger Kohn at (415) 744-1238.

Sincerely,

Gerardo Rios
Acting Chief, Permits Office
Air Division

cc: Mike Thabault, USFWS
Steve Hill, BAAQMD

# EXHIBIT F

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

July 12, 2001

Ellen Garvey
Air Pollution Control Officer
Bay Area AQMD
939 Ellis St.
San Francisco, CA 94109

Re: Issuance of Prevention of Significant Deterioration (PSD) permit to Mirant Delta, LLC for modification of Contra Costa Power Plant (CCPP)

Dear Ms. Garvey:

I am writing to notify the Bay Area Air Quality Management District (District or BAAQMD) that the U.S. Environmental Protection Agency (EPA) has concluded its consultation with the U.S. Fish and Wildlife Service (FWS) on the construction of Unit 8 at the Contra Costa Power Plant, as required by Section 7 of the Endangered Species Act (ESA), through use of the informal consultation process. As EPA has met its ESA obligations with respect to the permitting action that authorizes the construction of Unit 8, the District may issue a final PSD permit to Mirant Delta in accordance with the PSD Delegation Agreement between EPA and BAAQMD.

We appreciate your patience during the time that EPA was addressing ESA issues. If you have any questions, please call me or Roger Kohn of my staff at (415) 744-1238.

Sincerely,

for Gerardo C. Rios
Acting Supervisor, Permits Office
Air Division

cc: Mike Tollstrup, ARB
Ronald Kino, Mirant Delta, LLC

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be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

39. Prior to the issuance of the BAAQMD Authority to Construct for the CCPP Unit 8, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and 112.2 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

40. Prior to the start of construction of the CCPP Unit 8, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and 112.2 tons of Particulate Matter less than 10 microns. (Offsets)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of the CCPP Unit#8 shall submit an application to the BAAQMD for a significant revision to the Major Facility Review Permit prior to commencing operation. (Regulation 2-6-404.3)

42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the CCPP Unit 8 shall not operate either of the gas turbines until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Regulation 2, Rule 7)

43. The CCPP Unit 8 shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

44. The owner/operator shall take monthly samples of the natural gas combusted at the CCPP Unit#8. The samples shall be analyzed for sulfur content using District-approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. Sulfur content shall be no more than 1.0 grains/100scf. (cumulative increase)

45. The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 5,666 ppmw

(mg/l). The owner/operator shall sample the water at least once per day. (PSD)

46. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the CCPP Unit 8, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. The CEC CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the PM10 emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD)

47. The Fuel Gas Preheater (S-45) shall not be operated more than 16 hours in any day. (BACT)

# EXHIBIT D

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**REGION IX**
**75 Hawthorne Street**
**San Francisco, CA 94105**

June 21, 2004

Mr. Jack Broadbent
Air Pollution Control Officer
Bay Area AQMD
939 Ellis Street
San Francisco, CA 94109-7799

RE: PSD Re-delegation Agreement

Dear ~~Mr.~~ Jack Broadbent:

EPA appreciates the efforts of your staff to work with us to draft a partial re-delegation of the federal Prevention of Significant Deterioration (PSD) permitting program. I am pleased to enclose a signed copy of the revised PSD delegation agreement. The agreement is effective immediately.

Please contact Laura Yannayon at (415) 972-3534 if you have any other questions related to this matter.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosure

cc: Brian C. Bunger, Bay Area Air Quality Management District, w/ enclosure
Catherine Witherspoon, Executive Officer, California Air Resources Board w/enclosure

**U.S. EPA - Bay Area Air Quality Management District**

**Agreement for Re-Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21**

The undersigned, on behalf of the Bay Area Air Quality Management District (District) and the United States Environmental Protection Agency (EPA), hereby agree to the re-delegation of authority for the initial issuance or "administrative" or "minor" modification[1] of the Prevention of Significant Deterioration (PSD) permits identified below, subject to the terms and conditions of this agreement. This re-delegation is executed pursuant to 40 CFR 52.21(u), Delegation of Authority.

## I. BACKGROUND RECITALS

1. EPA had delegated authority to implement the federal PSD regulations at 40 CFR 52.21 for all sources and modifications to the District on April 23, 1986. On December 31, 2002, EPA finalized revisions to the regulations at 40 CFR 52.21, which became effective on March 3, 2003. 67 FR 80186. The revisions to 40 CFR 52.21 did not significantly alter those portions of 40 CFR 52.21 that concern the issuance of permits for newly constructed "greenfield" sources. See id. at 80187.
2. The District may need to revise its local regulations to fully implement the federal regulations at 40 CFR 52.21, effective March 3, 2003. Accordingly, on March 3, 2003, EPA withdrew the delegation of PSD authority from the District. See 68 FR 19371

[1] The terms "administrative" and "minor" modifications are defined the same as in the EPA memorandum entitled "Revised Draft Policy on Permit Modifications and Extensions" July 5, 1985, by Darryl Tyler, Director, Control Programs Development Division of US EPA Office of Air quality Planning and Standards.

(April, 21, 2003).

3. Because the federal regulations concerning permit issuance for new sources were not significantly altered effective March 3, 2003, existing District regulations continue to allow the District to implement 40 CFR 52.21 pursuant to a delegation agreement to complete the initial issuance or administrative or minor modification of the PSD permit(s). This delegation of authority does not extend to any modification that would be a "major" modification under 40 CFR 52.21, as amended on December 31, 2002. Any major modification shall be permitted by EPA pursuant to 40 CFR 52.21, as amended on December 31, 2002.

## II. APPLICABILITY

1. Pursuant to this re-delegation, the District shall have primary responsibility for initial issuance or administrative or minor modification of the PSD permit(s) identified below:

Facility:

a. Delta Energy Center
b. Los Medanos Energy Center
c. Metcalf Energy Center
d. East Altamont Energy Center
e. Tesla Power Plant
f. Russell City Energy Center
g. Delta Power Plant
h. Potrero Power Plant

2. Permitting History for Delta Energy Center (Delta #12095). The District issued a Preliminary Determination of Compliance (PDOC) on August 12, 1999. Subsequently, the District issued the Final Determination of Compliance (FDOC) on October 22, 1999. The Prevention of Significant (PSD)/Authority to Construct (ATC) was issued on March

28, 2000. The Title IV/V permit was issued on March 19, 2003 and reissued on November 12, 2003. The Permit to Operate was issued on January 8, 2003, and modified on November 14, 2003.

3. Permitting History for Los Medanos Energy Center (Los Medanos #11866). The District issued a PDOC on March 18, 1999. Subsequently, the District issued the FDOC on June 10, 1999. The PSD/Authority to Construct was issued on September 10, 1999 and the Authority to Construct was superceded on July 2, 2001. The Title IV/V permit was issued on September 1, 2001 and modified on January 13, 2004. The District Permit to Operate was issued on May 19, 2002.
4. Permitting History for Metcalf Energy Center (Metcalf # 12183). The District issued the FDOC on August 24, 2000. The final PSD permit was issued on May 4, 2001. The Authority to Construct was issued on February 13, 2002 and a modification was granted on September 10, 2002.
5. Permitting History for East Altamont Energy Center (East Altamont # 13050). The District issued a PDOC on April 12, 2002. Subsequently, the District issued the FDOC on July 10, 2002. The Western Area Power Administration (WAPA) formally requested that US Fish and Wildlife (US FWS) initiate formal Section 7 consultation on February 11, 2002. The Authority to Construct has not been issued as of May 7, 2004.
6. Permitting History for Tesla Power Plant (Tesla # 13424). The District issued a PDOC on August 6, 2002. Subsequently, the District issued the FDOC on January 22, 2003. The EPA formally requested that US FWS initiate formal Section 7 consultation on

February 21, 2002. The final PSD permit is not issued because of a delay in the issuance of the Biological Opinion associated with Section 7 process. The California Energy Commission conducted an Evidentiary Hearing from September 8 to September 12, 2003. The Commissioners have not made a final determination as of May 7, 2004.

7. Permitting History for Russell City Energy Center (Russell City # 13161). The District issued a PDOC on October 25, 2001. Subsequently, the District issued the FDOC in March 2002 and an Authority to Construct on May 14, 2003. The EPA formally requested that US FWS initiate formal Section 7 consultation on March 11, 2002. The final PSD permit has not been issued because of a delay in the issuance of the Biological Assessment associated with the Endangered Species Act Section 7 process.
8. Permitting History for Delta Power Plant (Delta #18, Unit 8). The District issued a FDOC on February 2, 2001. The final PSD permit and Authority to Construct were issued on July 24, 2001. The Permit to Operate has not yet been issued as of May 7, 2004.
9. Permitting History for Potrero Power Plant (Potrero #26, Unit 7). The FDOC was issued on December 12, 2001. On July 25, 2003, Mirant of California (owner of the Potrero Power Plant) revised their application (#7951) to include a cooling tower system and reduce the annual hours of operation. A draft Biological Opinion and Incidental Take Statement were provide to EPA and the Army Corps of Engineers on April 2, 2003. NOAA Fisheries received comments on the draft Biological Opinion from EPA on May 6, 2003. The comments pertained to a revised description of EPA's federal action

regarding the issuance of the air quality permit. EPA comments also stated that the Corps has agreed to place all terms and conditions contained in the Incidental Take Statement of the April 2, 2003, draft Biological Opinion, in the Corps Section 404 Clean Water Act and in any Rivers and Harbor Act permits. The amended PDOC has not been issued as of May 7, 2004.

10. To allow the District to continue to issue and/or process minor modifications to the PSD permit(s) for Delta Energy, Los Medanos, Metcalf, East Altamont, Tesla, Russell City, Delta Power and Potrero, EPA and the District have agreed to this re-delegation of PSD authority to issue initial permits or make administrative or minor modifications, until the facility commences normal operations. If any of the facilities subject to this agreement requests a permit modification to incorporate conditions for a plantwide applicability limit or a clean unit exclusion, as provided in 40 CFR 52.21(aa) and 52.21(x) & (y), respectively, EPA shall process and issue any applications for a permit modification. EPA may review the PSD permit to ensure that the District's implementation of this agreement is consistent with federal regulations (40 CFR 52.21).

11. The District shall send to EPA a copy of all public notices required by 40 CFR 124.

## III. GENERAL CONDITIONS

1. The District shall request and follow EPA guidance on any matter involving the interpretation of Sections 160-169 of the Clean Air Act or 40 CFR 52.21, relating to the PSD permits for Delta Energy, Los Medanos, Metcalf, East Altamont, Tesla, Russell City, Delta Power and Potrero.

2. The District shall issue PSD permits under this Agreement in accordance with the PSD elements of the District's Regulation 2, Rule 2 and 40 CFR 52.21 as amended on December 31, 2002. Elements of Regulation 2, Rule 2 relating to state law requirements inconsistent with the Clean Air Act and 40 CFR 52.21 and 124, including, but not limited to, elements of Regulation 2, Rule 2 relating to the California Environmental Quality Act, shall not apply to PSD permits under this Agreement.
3. This re-delegation may be amended at any time by the formal written agreement of both the District and the EPA, including amendment to add, change, or remove conditions or terms of this agreement.
4. If the U.S. EPA determines that the District is not administering the PSD permit identified in this agreement in accordance with the terms and conditions of this re-delegation, the requirements of 40 CFR 52.21, 40 CFR 124, or the Clean Air Act, this re-delegation, after consultation with the District, may be revoked in whole or in part. Any such revocation shall be effective as of the date specified in a Notice of Revocation to the District.
5. If the District determines that administering the permits identified in this agreement in accordance with the terms and conditions of this agreement, the requirements of 40 CFR 52.21, 40 CFR 124, or the Clean Air Act conflicts with State or local law, or exceeds the District's authority or resources to fully and satisfactorily carry out such responsibilities, the District after consultation with EPA may remand administration of these permits to EPA. Any such remand shall be effective as of the date specified in a Notice of Remand

to EPA.

6. The permit appeal provisions of 40 CFR 124, including subpart C thereof, pertaining to the Environmental Appeals Board (EAB), shall apply to all appeals to the Administrator on permits and modifications to permits issued by the District under this re-delegation. For purposes of implementing the federal permit appeal provisions under this re-delegation, if there is a public comment requesting a change in a draft preliminary determination or draft permit conditions, the final permit issued by the District shall contain a statement that for Federal PSD purposes and in accordance with 40 CFR 124.15 and 124.19, (1) the effective date of the permit shall be 30 days after the date of the final decision by the District to issue, modify, or revoke and reissue the permit; and (2) if an appeal is made to the EAB through the Administrator, the effective date of the permit shall be suspended until such time as the appeal is resolved. The District shall inform EPA Region IX in accordance with conditions of this re-delegation when there is public comment requesting a change in the preliminary determination or in a draft permit condition. Failure by the District to comply with the terms of this paragraph shall render the subject permit invalid for Federal PSD purposes.
7. Pursuant to the provisions of 40 CFR 52.21(u)(2), the District shall consult with the appropriate State or local agency primarily responsible for managing land use prior to making any determinations under this Agreement.
8. Nothing in this agreement shall prohibit EPA from enforcing the PSD provisions of the Clean Air Act, the PSD regulations or any PSD permit issued by the District pursuant to

this agreement. In the event that the District is unwilling or unable to enforce a provision of this re-delegation with respect to a source subject to the PSD regulations, the District will immediately notify the Regional Administrator. Failure to notify the Regional Administrator does not preclude EPA from exercising its enforcement authority.

9. This re-delegation of authority becomes effective upon the date of the signatures of both parties to this Agreement.

June 16, 2004
Date

Jack Broadbent
Air Pollution Control Officer
Bay Area Air Quality Management District

June 21, 2004
Date

Deborah Jordan
Director, Air Division
U.S. EPA, Region IX

# EXHIBIT E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

FEB 04 2008

Mr. Jack Broadbent
Air Pollution Control Officer
Bay Area AQMD
939 Ellis Street
San Francisco, CA 94109-7799

RE: Amended PSD Delegation Agreement

Dear ~~Mr. Broadbent~~ Jack:

EPA appreciates the efforts of your staff to work with us in amending your Prevention of Significant Deterioration (PSD) Delegation agreement between the District and EPA. Under the amended delegation agreement, the District is now primarily responsible for issuing and modifying PSD permits. EPA remains available to assist the District in any applicability or implementation issues. I am pleased to enclose a signed copy of the revised PSD delegation agreement. The agreement is effective immediately.

Please contact Laura Yannayon at (415) 972-3534 if you have any other questions related to this matter.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosure

cc: Brian C. Bunger, Bay Area Air Quality Management District, w/enclosure
James Goldstene, Executive Officer, California Air Resources Board w/enclosure

Printed on Recycled Paper

**U.S. EPA - Bay Area Air Quality Management District**

**Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21**

The undersigned, on behalf of the Bay Area Air Quality Management District (District) and the United States Environmental Protection Agency (EPA), hereby agree to the partial delegation of authority to issue Prevention of Significant Deterioration (PSD) initial permits and to modify existing PSD permits, subject to the terms and conditions of this Agreement. This partial delegation is executed pursuant to 40 CFR 52.21(u), Delegation of Authority.

## I. Background Recitals

1. On April 23, 1986, EPA delegated authority to implement the federal PSD regulations at 40 CFR 52.21 to the District. This delegation was based on EPA's determination that the PSD portion of District Regulation 2 – Rule 2 (Readopted and Renumbered July 17, 1991, amended June 15, 1994) generally met the requirements of 40 CFR 52.21; therefore District permits issued in accordance with the provisions of Regulation 2 – Rule 2 were deemed to meet the federal PSD permit requirements pursuant to the provisions of the delegation agreement.

2. On December 31, 2002, EPA finalized revisions to the regulations at 40 CFR 52.21, which became effective on March 3, 2003. See 67 FR 80186. After discussions with the California Air Resources Board and the District, EPA informed the District that it would need to adopt revisions to Regulation 2 – Rule 2 to address the recent PSD revisions and continue to implement the federal PSD program pursuant to 40 CFR 52.21. Accordingly, on March 3, 2003, EPA withdrew the delegation of federal PSD authority from the District. See 68 FR 19371 (April 21, 2003).

3. On June 24, 2005, the District of Columbia Court of Appeals vacated two provisions of the revised federal PSD regulations related to Clean Units and Pollution Control Projects. The provisions upheld by the Court provide new additional calculation methodologies for determining if a proposed project will result in a major modification and the application

of a Plantwide Applicability Limit (PAL). On June 13, 2007, EPA issued a direct final rule revising the federal PSD regulations to remove the vacated portions.

## II. Scope of Partial Delegation

1. The provisions upheld by the court (additional calculation methodologies and PALs) are not specifically addressed by Regulation 2 – Rule 2. Therefore, this partial delegation of authority to issue and modify PSD permits does not delegate authority to the District to modify PSD permits when the applicant seeks to use the additional calculation methodologies promulgated in 40 CFR 52.21 but not set forth in Regulation 2 – Rule 2 and does not delegate authority to issue new or modified PSD permits based on PALs.

2. For all applications for new or modified PSD permits other than those set forth in paragraph 1 above, the existing District regulations continue to generally meet the requirements of 40 CFR 52.21 for issuing PSD permits; therefore District permits issued in accordance with the provisions of Regulation 2 – Rule 2 shall be deemed to meet federal PSD permit requirements pursuant to the provisions of this delegation agreement.

## III. Applicability

1. EPA and the District have agreed to this partial delegation of PSD authority to allow the District to issue initial and modified PSD permits, except for modifications seeking to determine PSD applicability based on the additional calculation methodologies set forth in 40 CFR 52.21 and new or modified PSD permits seeking PALs. (Modifications include Administrative Amendments, Major Modifications, and non-Major Modifications.)

2. Pursuant to this partial delegation agreement, the District shall have primary responsibility for issuing all new and modified PSD permit(s).

3. The authority to issue a PSD permit containing a PAL is not delegated to the District as part of this delegation agreement. If any facility subject to this agreement requests a permit modification to incorporate conditions for a PAL, as provided in 40 CFR 52.21(aa), EPA shall process the application and issue the final PAL permit for the modification.

4. If any source seeks a PSD permit modification based on determining applicability with the additional calculation methodologies set forth in 40 CFR 52.21 (as revised in 2002), EPA shall issue the PSD permit.

5. This partial delegation of PSD authority becomes effective upon the date of the signatures of both parties to this Agreement.

## IV. General Delegation Conditions

1. The District shall issue PSD permits under this partial delegation Agreement in accordance with the PSD requirements of the District's Regulation 2 – Rule 2 and 40 CFR 52.21, as amended on December 31, 2002, except as provided in subsection III.

2. This partial delegation may be amended at any time by the formal written agreement of both the District and the EPA, including amendments to add, change, or remove terms or conditions of this Agreement.

3. EPA may review the PSD permit(s) issued by the District to ensure that the District's implementation of this delegation Agreement is consistent with federal PSD regulations for major sources and major modifications (40 CFR 52.21).

4. If the EPA determines that the District is not implementing or enforcing the PSD program in accordance with the terms and conditions of this partial delegation agreement, the requirements of Regulation 2 – Rule 2, 40 CFR 52.21, 40 CFR 124 or the Clean Air Act, this partial delegation agreement may be revoked in whole or in part. Any such revocation shall be effective as of the date specified in a Notice of Revocation to the District.

5. If the District determines that issuing a PSD permit in accordance with the terms and conditions of this agreement, the requirements of Regulation 2 – Rule 2, 40 CFR 52.21, 40 CFR 124 or the Clean Air Act conflicts with State or local law, or exceeds the District's authority or resources to fully and satisfactorily carry out such responsibilities, the District after consultation with EPA, may remand administration of these permits to EPA. Any such remand shall be effective as of the date specified in a Notice of Remand to EPA.

6. The permit appeal provisions of 40 CFR 124, including subpart C thereof, pertaining to the Environmental Appeals Board (EAB), shall apply to all federal PSD permitting action appeals to the EAB for permits issued by the District under this partial delegation agreement. For purposes of implementing the federal permit appeal provisions under this partial delegation, if there is a public comment requesting a change in a draft preliminary determination or draft permit conditions, the final permit issued by the District shall contain a statement that for federal PSD purposes and in accordance with 40 CFR 124.15 and 124.19, (1) the effective date of the permit shall be 30 days after the date of the final decision by the District to issue, modify, or revoke and reissue the permit; and (2) if an appeal is made to the EAB, the effective date of the permit shall be suspended until such time as the appeal is resolved. Failure by the District to comply with the terms of this paragraph shall render the subject permit invalid for PSD purposes.

## V. Communication Between EPA and the District

The District and EPA will use the following communication procedures:

1. The District will forward to EPA copies of (1) the findings related to the PSD application, (2) the justification for the District's preliminary determination, (3) the draft permit and (4) all public notices required by 40 CFR 124. Such copies shall be provided at or prior to the beginning of the public comment period for each PSD preliminary determination. EPA will provide comments to the District as soon as possible prior to the close of the public comment period.

2. The District will forward to EPA copies of the final action for each PSD permit application at the time of issuance, as well as a summary of public comments and, upon request by EPA, copies of substantive public comments.

3. The District will send to EPA a copy of all PSD non-applicability determinations that utilize netting. All such determinations must be accompanied by a written justification.

## VI. EPA Policies Applicable to PSD Review

1. EPA is responsible for the issuance of PSD permits on Indian Lands, under Sections 110 and 301 of the Clean Air Act and for those situations set forth in Section III above. This

agreement in no way grants or delegates any authority under the Clean Air Act on Indian Lands to the District.

2. All PSD BACT determinations are required to perform a "top-down" BACT analyses. EPA will consider as deficient any BACT determination that does not begin with the most stringent control options available for that source category.

3. The District must consult with the appropriate Federal, State and local land use agencies prior to issuance of a PSD permit preliminary determination. For the purposes of the Endangered Species Act (ESA), the District shall:

   a. Notify the appropriate Federal Land Manager (FLM) within 30 days of receipt of a PSD permit application. If the proposed project will impact a Class I area, notify the appropriate Federal Land Manager (FLM) no later than 60 days prior to issuing a public notice for the project.

   b. Notify the Fish and Wildlife Service (FWS) and EPA when a submitted PSD permit application has been deemed complete, in order to assist EPA in caring out its non-delegable responsibilities under Section 7 of the ESA (PL 97-304).

   c. Notify applicants of the potential need for consultation between EPA and FWS if an endangered species may be affected by the project.

   d. Refrain from issuing a final PSD permit unless FWS has determined that the proposed project will not adversely affect any endangered species.

## VII. Permits

1. The District shall follow EPA guidance on any matter involving the interpretation of Sections 160-169 of the Clean Air Act or 40 CFR 52.21, relating to applicability determinations, PSD permit issuance and enforcement.

2. The District will at no time grant any waiver to the PSD permit requirements.

3. Authorities to Construct must include appropriate provisions to ensure permit enforceability. Permit conditions shall, at a minimum, contain reporting requirements on initiation of construction, start-up, and source testing (where applicable).

4. When any conditions of a PSD permit are incorporated into a Title V permit, the District shall clearly identify PSD as the basis for those conditions.

5. The primary responsibility for the administration and enforcement of the following EPA-issued permits is delegated to the District:

| Facility | EPA File Number | Permit Issuance Date |
|---|---|---|
| Calpine Gilroy Cogen | SFB 84-04 | August 1, 1985 |
| Cardinal Cogen | SFB 82-04 | June 27, 1983 |
| Crockett Cogen | SFB 82-05 | February 9, 1983 |
| IBM Corporation | SFB 82-01 | June 9, 1982 |
| Martinez Cogen Limited Partnership | SFB 83-01 | December 13, 1983 |
| Tosco Corporation | SFB 78-07 | December 18, 1978 |
| Tosco SF Area Refinery at Rodeo | SFB 85-03 | March 3, 1986 |

District-issued modifications to these permits which meet the requirements of 40 CFR 52.21 will be considered valid by EPA. The District shall issue any permit modifications to the above listed sources pursuant to this agreement and using District Regulation 2 – Rule 2, which incorporates the requirements of 40 CFR 52.21.

## VIII. Permit Enforcement

1. The primary responsibility for enforcement of the PSD regulations rests with the District. The District will enforce the provisions of the PSD program except in those cases where District rules or policy are more stringent. In that case, the District may elect to implement the more stringent requirements.

2. Nothing in this partial delegation agreement shall prohibit EPA from enforcing the PSD provisions of the Clean Air Act, 40 CFR 52.21 or any PSD permit issued by the District pursuant to this agreement.

3. In the event that the District is unwilling or unable to enforce a provision of this partial delegation agreement with respect to a source subject to the PSD regulations, the District will immediately notify the Air Division Director. Failure to notify the

Air Division Director does not preclude EPA from exercising its enforcement authority.

Jan. 29, 2008
Date

Jack P. Broadbent
Executive Officer/APCO
Bay Area Air Quality Management District

Feb. 6, 2008
Date

Deborah Jordan
Director, Air Division
U.S. EPA, Region IX

# EXHIBIT F

**Pacific Gas and Electric Company**
Power Generation
Fossil Plant Construction

Gateway Generating Station
3225 Wilbur Ave.
Antioch, CA 94509
(925) 459-7200

December 18, 2007
GGS-L-00041C

Jack Broadbent
Executive Officer and APCO
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Application for Modifications to Authority to Construct
Gateway Generating Station - Plant No. 18143

Dear Mr. Broadbent:

PG&E is pleased to submit this application for modifications to the authority to construct (ATC) for the Gateway Generating Station in Antioch. The ATC for the project (formerly the Contra Costa Unit 8 Power Project) was originally issued on July 24, 2001, following certification by the California Energy Commission (CEC) on May 30, 2001. Construction of the facility started late in 2001 and was suspended in February 2002, with approximately 7 percent of construction completed. The ATC, which has been renewed three times (in 2003, 2005 and 2007) was transferred to PG&E in January 2007 under the new project name. PG&E restarted construction of the Gateway Generating Station on February 5, 2007, and anticipates that first fire of the first gas turbine will occur on August 29, 2008.

Following its acquisition of the project, PG&E evaluated the facility as originally permitted and determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. The proposed modifications are described in detail in the attached application support document.

Forms P-101B, C, ICE, P, A and HRSA are attached, and supplemental information regarding the proposed project is provided in the enclosed application support document. The filing fee and initial fee payment will be submitted to the District under separate cover. A separate application is being submitted to the CEC, as required under the conditions of the project's CEC license.

If you have any questions regarding the proposed project, please do not hesitate to call me or Nancy Matthews of Sierra Research at (916) 444-6666.

Sincerely,

Thomas Allen
Project Manager

attachments
cc: Teresa DeBono, PG&E
Andrea Grenier, Grenier & Associates, Inc.
Scott Galati, Galati & Blek
Nancy Matthews, Sierra Research
Regional Administrator, USEPA Region 9

sierra research

# Application to the Bay Area Air Quality Management District for Modifications to the Authority to Construct for the Gateway Generating Station Antioch, CA

prepared for:

**Pacific Gas & Electric Company**

December 2007

prepared by:

Sierra Research, Inc.
1801 J Street
Sacramento, California 95814
(916) 444-6666

# APPLICATION TO THE
# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
# FOR MODIFICATIONS TO THE AUTHORITY TO CONTRUCT
# FOR THE GATEWAY GENERATING STATION
# ANTIOCH, CALIFORNIA

Prepared for:

Pacific Gas & Electric Company

December 2007

Prepared by:

Sierra Research, Inc.

1801 J Street

Sacramento, CA 95811

(916) 444-6666

## SUMMARY

Pacific Gas & Electric Company (PG&E) completed the acquisition of Contra Costa Unit 8 (CC8) from Mirant Delta, LLC in late 2006 and subsequently received approval from the California Energy Commission to change the name of the project to the Gateway Generating Station. The Bay Area Air Quality Management District (District) has transferred the Authorities to Construct (ATCs) for the Gateway Generating Station project to PG&E. PG&E has evaluated the facility as originally permitted and has determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. With this application, PG&E is proposing to make the following changes to the permitted facility:

- Eliminate the 10-cell wet cooling tower and replace it with a dry cooling system, including an exempt wet surface air cooler;
- Replace the permitted natural gas-fired preheater with a smaller dewpoint heater and increase allowable daily hours of operation;
- Change the allowable emission rates for the gas turbines during startup operations;
- Reduce the permitted hourly emission rates for NOx, CO and $PM_{10}$, based on current BACT and on operating experience from other 7FA gas turbine facilities;
- Increase the daily and annual emission rates for CO, based on operating experience from other 7FA gas turbine facilities;
- Change the allowable emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Add a 300 hp Diesel fire pump at the facility.

These changes will require the following types of changes to the permit conditions:

- Eliminate conditions related to the wet cooling tower;
- Revise conditions related to the natural gas-fired preheater;
- Revise conditions related to emission limits during startup;
- Reduce allowable hourly NOx, CO and $PM_{10}$ emission limits for the Gas Turbines and Heat Recovery Steam Generators (HRSGs);
- Increase allowable daily and annual CO emission limits for the Gas Turbines and HRSGs;
- Revise the commissioning limits; and
- Revise the requirements related to emissions offsets.

This application support document discusses the proposed modifications, presents revised emissions calculations and ambient air quality modeling results, demonstrates the project's continued compliance with all applicable rules and regulations, and provides proposed revisions to the permit conditions. The only annual emissions increase proposed in this application is for

CO. Since the proposed annual increase in CO emissions is above the PSD significance threshold, the proposed modification is subject to PSD review for CO.

**APPLICATION TO THE BAY AREA AIR QUALITY MANAGEMENT DISTRICT FOR MODIFICATIONS TO THE AUTHORITY TO CONTRUCT FOR GATEWAY GENERATING STATION ANTIOCH, CALIFORNIA**

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# PART I. PROJECT DESCRIPTION

## A. Applicant's Name and Business Description

Name: Pacific Gas & Electric Company

Address: 3225 Wilbur Avenue
Antioch, CA 94509

Contact: Tom Allen, Project Manager
(925) 459-7200

Mailing Address for Permits:

Same as above, with copy to:

Sierra Research
1801 J Street
Sacramento, CA 95811

General Business Description: Electric generation

Responsible Official:

John S. Keenan, Senior VP Generation and CNO
Pacific Gas & Electric Company

Air Quality Consultants:

Sierra Research
1801 J Street
Sacramento, CA 95811
Contact: Nancy Matthews
(916) 444-6666

Type of Use Entitlement: PG&E will own and operate the project.

Estimated Construction Date: Construction of the permitted units is underway, in accordance with the existing Authority to Construct. Construction of the exempt units (including the air-cooled condenser in place of the cooling tower) is also underway. Construction of the proposed modifications to permit units, the dewpoint heater and fire pump engine, is expected to begin upon issuance of the revised Authority to Construct.

## B. Type of Application

This is an application for modification to existing Authorities to Construct.

## C. Description of the Proposed Project

The Gateway Generating Station Project (formerly Contra Costa Unit 8, or CC8) was permitted to consist of the following equipment:

- S-41 and S-43: Two Combustion Gas Turbines, General Electric Frame 7FA Model PG 7231 or equivalent; equipped with dry low-NOx combustors, abated by selective catalytic reduction systems and oxidation catalysts;
- S-42 and S-44: Two Heat Recovery Steam Generators (HRSGs), equipped with low-NOx duct burners, abated by selective catalytic reduction systems and oxidation catalysts;
- S-46: One 10-cell wet cooling tower;
- S-45: One natural gas-fired preheater; and
- S-48: One oil-water separator.

PG&E proposes to make several changes to the Gateway Generating Station Project (GGS) permit, as follows:

- Eliminate S-46, the 10-cell wet cooling tower, and replace it with an air-cooled condenser and a wet surface-air cooler, both of which are exempt from District permitting requirements;
- Replace the permitted natural gas-fired preheater, S-45, with a smaller unit and increase its allowable daily hours of operation;
- Change the allowable emission rates for the gas turbines during startup and shutdown operations;
- Reduce the permitted hourly mass emission and concentration limits for NOx, CO and $PM_{10}$, based on current BACT and operating experience;
- Change the ammonia slip limit;
- Reduce the permitted $PM_{10}$ emissions for the project;
- Increase the permitted daily and annual CO emissions for the project to reflect the revised CO startup emission rates;
- Revise the allowable CO and POC emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Add a 300 kW Diesel fire pump engine.

As a result of these proposed changes, PG&E is requesting permit condition changes that will reflect the revised emission rates and operating conditions for the permitted units. The overall increases in allowable CO emissions from the facility will trigger PSD review for that pollutant. Because the cooling tower is being eliminated, annual $PM_{10}$ emissions, and therefore the facility's $PM_{10}$ offset obligations, will be reduced.

## D. Project Emissions

This section of the application presents an assessment of the emissions from the revised PG&E project design. These revisions include reducing the NOx and CO emissions from the gas turbines and HRSGs to reflect current BACT; reducing the $PM_{10}$ emission limit for the units during duct firing; changing the ammonia slip limit; eliminating the wet cooling tower and associated $PM_{10}$ emissions; and adding a new Diesel-fueled fire pump engine. The analysis of the new project design also includes reductions in NOx and increases in CO from the gas turbines during startup.

### 1. Emissions from the Gas Turbines and HRSGs

The gas turbine and duct burner emission rates have been estimated from vendor data, current BACT limits, new maximum fuel consumption rates, and established emission calculation procedures. The changes in emissions are a result of: (1) the proposed reductions in NOx, CO and $PM_{10}$ concentrations and mass emission limits during normal operations; and (2) revised emission rates and operating assumptions for the turbines during startup. The maximum emission rates for the combustion turbines alone and for the combustion turbines with duct burners are shown in Tables 1 and 2, respectively. The emission data and operating parameters that are the basis for these emission rates are shown in Appendix A, Table A-1. Proposed new emission limits during turbine startup are shown in Table 3.

**Table 1**
**Maximum Pollutant Emission Rates**
**Each Gas Turbine[1]**

| Pollutant | ppmvd @ 15% $O_2$ | lb/MMBtu | lb/hr[2] |
|---|---|---|---|
| NOx | 2.0[3] (2.5) | 0.0072 (0.009) | 13.40 |
| $SO_2$[4] | 0.57 | 0.0028 | 5.22 |
| CO | 4.0[3] (6.0) | 0.0088 (0.0132) | 16.31 |
| POC | 2.0[3] | 0.0017 | 4.67 |
| $PM_{10}$[5] | -- | -- | 11.0 |
| $NH_3$ | 10 (5) | -- | 24.80 |

Notes:
1. Emission rates shown reflect the highest value at any operating load, without duct firing. Numbers in parentheses show current limit where changes are proposed.
2. Current ATC does not include lb/hr limits for the CTGs without duct firing.
3. Current BACT.
4. Based on maximum fuel sulfur content of 1 grain per 100 standard cubic feet.
5. 100% of particulate matter emissions assumed to be emitted as $PM_{10}/PM_{2.5}$; $PM_{10}$ emissions include both front and back half as those terms are used in USEPA Method 5.

| Table 2<br>Maximum Pollutant Emission Rates<br>Each Turbine with Duct Burners[1] | | | |
|---|---|---|---|
| Pollutant | ppmvd @ 15% $O_2$ | lb/MMBtu | lb/hr |
| NOx | 2.0[2] (2.5) | 0.0072 (0.009) | 15.18 (20) |
| $SO_2$[3] | 0.57 | 0.0028 | 5.92 (6.18) |
| CO | 4.0[2] (6.0) | 0.0088 (0.0132) | 18.49 (29.22) |
| POC | 2.0[2] | 0.0017 | 5.29 (5.6) |
| $PM_{10}$[4] | -- | -- | 12(13) |
| $NH_3$ | 10 (5) | -- | 28.10 |

Notes:
1. BAAQMD permit limit. Numbers in parentheses show current limit where changes are proposed.
2. Current BACT.
3. Based on maximum fuel sulfur content of 1 grain per 100 standard cubic feet.
4. 100% of particulate matter emissions assumed to be emitted as $PM_{10}/PM_{2.5}$; $PM_{10}$ emissions include both front and back half as those terms are used in USEPA Method 5.

| Table 3<br>Maximum Emission Rates During Turbine Startup (Each Turbine)[1] | | | |
|---|---|---|---|
| | NOx | CO | POC |
| Cold Start, lb/hour | 160 (n/a) | 900 (n/a) | 16 (n/a) |
| Cold Start, lb/start[2] | 600 (452) | 5,400 (990) | 96 (109) |
| Hot Start, lb/start[3] | 160 (189) | 900 (291) | 16 (26) |

Notes:
1. Estimated based on operating experience for other 7FA CTGs in combined cycle. See Appendix A, Table A-1. Numbers in parentheses show current limit where changes are proposed.
2. Maximum of six hours per cold start.
3. Maximum of one hour per hot start.

The current permit conditions include separate emissions limits for cold startup, hot startup and shutdown. PG&E proposes to eliminate these separate limits and replace them with a single set of limits expressed in units of pounds per hour and pounds per startup. The proposed pounds per startup limit assumes a maximum of six hours for a full cold start.

Components of the gas turbine combustor assemblies must be replaced periodically because these components have a limited operational life. After the new gas turbine combustor components are installed, each gas turbine's fuel system must be tuned to meet the manufacturer's specifications for emissions and acoustic dynamics. During this tuning process

the turbines must operate at low loads intermittently for up to six hours with potentially elevated emission rates. Combustor tuning activities would also be covered by the proposed startup emission limits.

**NOx Emissions Excursions**

In the experience of many operators of gas turbines that are controlled to extremely low NOx levels using dry low-NOx combustors, there are some short-term turbine operating conditions that may cause temporarily elevated NOx levels. During these brief periods, the turbine-out NOx emissions are elevated to levels that exceed the SCR system's ability to maintain compliance with the 2 ppmc NOx limit on a one-hour average basis. PG&E requests that the District include in the revised permit a condition that allows a limited number of excursions above the 2 ppmc limit so that these conditions that are beyond the operator's control will not be considered violations of the permitted emissions limit. This excursion language has been included in many permits issued for gas turbines since 2001, when NOx limits became extremely stringent and averaging periods were reduced to one hour. The proposed condition language is as follows:

> *Compliance with the hourly NOx emission limits specified in Condition 20a shall not be required during short-term excursions of less than 10 hours per rolling 12-month period.*
>
> *Short-term excursions are defined as 15-minute periods designated by the applicant, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2 ppmvd corrected to 15% $O_2$. Maximum 1-hour average NOx concentrations for periods that include short-term excursions shall not exceed 30 ppmvd corrected to 15% $O_2$. All emissions during short-term excursions shall be included in all calculations of daily and annual mass emissions required by this permit.*

**Ammonia Slip Limit**

PG&E is also proposing to change the ammonia slip limit from 5 ppmvd @ 15% $O_2$ (ppmc), as specified in Condition 20e, to 10 ppmc. This request is made in conjunction with reducing the NOx limit from 2.5 ppmc to 2.0 ppmc on a 1-hour average basis. Although the previous owner of the project had agreed to meet a 5 ppmc ammonia slip limit, that limit was combined with a 2.5 ppmc NOx limit. Because of the additional demands on the NOx control system to achieve a 2.0 ppmc NOx limit, it would be extremely difficult to maintain continuous compliance with a 5 ppmc ammonia slip limit. The screening health risk assessment provided in Section II.B demonstrates that there are no significant public health impacts associated with the 10 ppmc ammonia slip level.

Moreover, we do not believe there is an air quality basis for requiring a lower ammonia slip level for the project. In a previous FDOC for a project in the Bay Area, the BAAQMD staff stated:[1]

> *...it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter.*

The assessment of ammonia emissions and the screening health risk assessment in the CC8 FDOC were based on an ammonia slip limit of 10 ppmvd, so the proposed change will not affect the analyses presented there. However, by agreement of the original applicant, the limit was changed in the final permit conditions from 10 ppmvd to 5 ppmvd.

2. Emissions from the Turbine Cooling System

PG&E has eliminated wet cooling from the project design and is using an air-cooled condenser (ACC) system instead. Components of the wet cooling system that will no longer be required and have therefore been eliminated from the original project design include the water supply pipeline, wet cooling tower, surface condenser, associated convenience systems, and the cooling tower chemical treatment system. New components to support the ACC system include a condensate polishing system, a new water supply source, and a wastewater discharge source. There are no air emissions associated with the ACC system.

The project as permitted incorporated evaporative cooling on the combustion turbine air inlets. However, due to the change in the project's water supply, PG&E proposes to eliminate this option and replace the evaporative cooling system with an electric chiller system. There are no air emissions associated with the electric chiller system.

In addition to the changes in the cooling water system, PG&E has also reviewed the water demand of the combustion turbine's steam power augmentation (PAG) systems. As a result of this review, PG&E has determined that the water demand and economic implications do not warrant implementing PAG on the combustion turbines.

Finally, PG&E has determined that a small fin-fan heat exchanger in combination with a wet surface air cooled (WSAC) heat exchanger system will be used to provide the necessary heat rejection capacity for auxiliary plant systems. The proposed fin-fan system is similar to the ACC system. The WSAC system is a hybrid between a wet cooling tower and fin-fan heat exchanger, and uses water sprayed over the heat transfer bundles to increase the cooling capacity of the system.

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[1] Final Determination of Compliance, East Altamont Energy Center LLC, July 10, 2002, p. 12.

Based on the conservatively high operating assumptions shown in Appendix A, Table A-2, emissions from the WSAC will be less than 1 lb/hr and 1 tpy. In the WSAC process, the warm process water is cooled in a closed-loop tube bundle so the process water being cooled never comes in contact with the outside air. Therefore, the WSAC is exempt from permitting under BAAQMD Rule 2, Section 2-1-128.4 ("Water cooling towers and water cooling ponds not used for evaporative cooling of process water, or not used for evaporative cooling of water from barometric jets or from barometric condensers").[2]

3. Emissions from the Dewpoint Heater

The current version of the ATC includes a natural gas-fired fuel gas preheater (dewpoint heater) rated at 12 MMBtu/hr. The ATC includes a condition limiting daily heat input to the fuel gas preheater to 192 MMBtu/day, effectively restricting the heater to 16 hours per day of operation. PG&E anticipates the need to operate the dewpoint heater up to 24 hours a day under some ambient conditions, so is proposing to substitute a smaller unit rated at approximately 6.5 MMBtu/hr (HHV). Specifications for the dewpoint heater are shown in Appendix A, Table A-3. Emissions from the replacement heater are shown in Table 4.

**Table 4**
**Maximum Pollutant Emission Rates**
**Natural Gas-Fired Dewpoint Heater**

| Pollutant | ppmvd @ 3% $O_2$[1] | lb/MMBtu (HHV)[1] | lb/hr[2] | lb/day[3] |
|---|---|---|---|---|
| NOx | 50 | 0.060 | 0.39 | 9.4 |
| $SO_2$[4] | -- | 0.0028[4] | 0.018 | 0.4 |
| CO | 40 | 0.029 | 0.19 | 4.6 |
| POC | 5.5 | 0.0045 | 0.029 | 0.7 |
| $PM_{10}$ | -- | 0.0074 | 0.048 | 1.2 |

Notes:
1. Performance from manufacturer at rated load.
2. Manufacturer's not-to-exceed emission rate.
3. Based on 24 hours per day of operation.
4. $SO_2$ emissions in lb/MMscf, based on natural gas sulfur content of 1 gr/100 scf.

[2] Rule 2, Section 2-1-128 exempts sources listed in the subsection, "provided that the source does not require permitting pursuant to Section 2-1-319." Section 2-1-319 requires permitting of sources with emissions in excess of 5 tpy.

4. Emissions from the Diesel Fire Pump Engine

PG&E is also proposing to install a 300 bhp emergency Diesel driven fire pump engine at GGS. The fire pump engine will be Tier 2-certified and will meet the requirements of the ARB Air Toxics Control Measure. Operation of the fire pump engine for testing and maintenance will be limited to one hour per day and 50 hours per year. Hourly and annual emissions from the Diesel fire pump engine are summarized in Table 5. Specifications for the fire pump engine are provided in Attachment A, Table A-4.

**Table 5**
**Maximum Pollutant Emission Rates**
**Emergency Diesel Fire Pump Engine**

| Pollutant | g/bhp-hr[1] | lb/hr | tons/yr[2] |
|---|---|---|---|
| NOx | 4.36 | 2.88 | 0.1 |
| $SO_2$[3] | -- | 0.0029 | <0.01 |
| CO | 0.32 | 0.21 | <0.1 |
| POC | 0.29 | 0.19 | <0.1 |
| $PM_{10}$[4] | 0.12 | 0.08 | <0.1 |

Notes:
1. Based on manufacturer's specifications for Clarke Model JU6H-UF40 Tier 2 fire pump engine.
2. Based on 50 hours per year of operation for testing and maintenance, per the ATCM.
3. Based on the use of ultra-low sulfur CARB Diesel fuel with maximum sulfur content of 15 ppm.

5. Fuel Use Limits for Permitted Equipment

The maximum heat input rates (fuel consumption rates) for the gas turbines and duct burners are shown in Table 6.

| Table 6<br>Hourly, Daily, and Annual Fuel Use[1] | | | |
|---|---|---|---|
| Units | Dewpoint Heater | Gas Turbines plus Duct Burners, each[2] | Total Fuel Use, all units[3] |
| MMBtu/hr | 6.5 (12) | 2094.4 (2227) | 4,195.3 |
| MMBtu/day | 156 (192)[4] | 50,265.6 (49,950) | 100,687.2 |
| MMBtu/yr | 56,940 | 34,900,000[5] | 34,956,940 |

Notes:
1. Numbers in parentheses show current permit limit where changes are proposed. MMBtu are HHV.
2. Based on maximum heat input for full load turbine operation at 23° F plus duct burner for maximum daily operation; based on full load turbine operation at 60° F plus duct burner, maximum of 22.5 hours per day and 5100 hours per year per duct burner for annual operation.
3. Includes S-41, S-42, S-43, S-44 and S-45.
4. Daily limit from ATC Condition 47.
5. Annual limit for both CTG trains, from ATC Condition 16.

6. Total Emissions for the Facility

The maximum annual, daily, and hourly emissions proposed for GGS are shown in Table 7. Detailed emissions calculations from the individual permit units are shown in Appendix A, Table A-5. Although the calculations of daily and annual emissions of NOx, $SO_2$ and POC show that emissions from the facility after the proposed permit changes are expected to be lower than the levels originally permitted for CC8, PG&E is not proposing to change the annual emission limits for these pollutants.

| Table 7<br>Emissions from Facility Equipment | | | | | |
|---|---|---|---|---|---|
| | NOx | $SO_2$ | CO | POC | $PM_{10}$ |
| Maximum Hourly Emissions, lb/hr | | | | | |
| Turbines and Duct Burners[1] | 175.2 | 11.8 | 918.5 | 21.3 | 22.0 |
| Dewpoint Heater | 0.4 | <0.1 | 0.2 | <0.1 | <0.1 |
| Fire Pump Engine[2] | 2.9 | <0.1 | 0.2 | 0.2 | 0.1 |
| Total Project, pounds per hour[3] | 178.5 | 11.9 | 918.9 | 21.5 | 24.3 |
| Original Analysis[4] | 170 | 12.4 | 541 | 109 | 26 |
| Maximum Daily Emissions, lb/day | | | | | |
| Turbines and Duct Burners[1] | 1,746.6 | 284.0 | 11,465.6 | 382.6 | 576.0 |
| Dewpoint Heater | 9.4 | <0.1 | 4.6 | 0.7 | 1.2 |
| Fire Pump Engine[2] | 2.9 | <0.1 | 0.2 | 0.2 | 0.1 |

| Table 7<br>Emissions from Facility Equipment | | | | | |
|---|---|---|---|---|---|
| | NOx | $SO_2$ | CO | POC | $PM_{10}$ |
| Total Project, pounds per day[3] | 1,759.0 | 284.0 | 11,470.3 | 384.4 | 577.2 |
| Current Permit Limits[5] | 1,994 | 297 | 3,602 | 468 | 624 |
| **Permit Limits After Modification, lb/day** | **1,994** | **297** | **11,470.3** | **468** | **577.2** |
| Maximum Annual Emissions, tpy | | | | | |
| Turbines and Duct Burners[1] | 149.6 | 37.0 | 554.3 | 45.3 | 101.5 |
| Dewpoint Heater | 1.7 | 0.1 | 0.8 | 0.1 | 0.3 |
| Fire Pump Engine | 0.1 | <0.1 | <0.1 | <0.1 | <0.1 |
| Total Project, tons per year[3] | 151.4 | 37.0 | 555.1 | 45.4 | 101.7 |
| Current Permit Limits[5] | 174.3 | 48.5 | 259.1 | 46.6 | 112.2[6] |
| **Permit Limits After Modification, tpy** | **174.3** | **37.0** | **555.1** | **46.6** | **101.7** |

Notes:

1. Includes startup emissions.
2. Calculations reflect one hour per day and 50 hours per year of operation for the fire pump for testing and maintenance.
3. Numbers may not add directly due to rounding.
4. Appendix B of the FDOC, turbines and duct burners only. NOx, POC and CO emissions shown are emission rates during startup. $SO_2$ and $PM_{10}$ emissions reflect duct firing.
5. Current daily permit limit applies to gas turbines and HRSGs only; annual permit limit applies to all permitted units.
6. Current $PM_{10}$ limit includes wet cooling tower, which is being eliminated in this amendment.

7. Noncriteria Pollutant Emissions

The noncriteria pollutants that may be emitted from the gas turbines and HRSGs at GGS, and their respective emission factors, are shown in Table 8. Noncriteria pollutant emissions from the dewpoint heater, which total 6.3 lb/yr, are shown in detail in Table A-7, Appendix A. Diesel particulate matter (DPM) emissions from the Diesel fire pump engine will not exceed 4.0 lb/yr, based on 50 hours per year of operation for testing and maintenance.

**Table 8**
**Noncriteria Pollutant Emissions for the Gas Turbines with Duct Firing[1]**

| Pollutant | Emission Factor (lb/MMscf) | Emissions | |
|---|---|---|---|
| | | lb/hr, each | ton/yr, total (two trains) |
| Acetaldehyde | $4.08 \times 10^{-2}$ | 0.084 | 0.7 |
| Acrolein | $3.69 \times 10^{-3}$ | 0.0076 | $6.4 \times 10^{-2}$ |
| Ammonia[2] | --[3] | 28.1 | 238.9 |
| Benzene | $3.33 \times 10^{-3}$ | 0.0069 | $5.7 \times 10^{-2}$ |
| 1,3-Butadiene | $4.39 \times 10^{-4}$ | 0.0009 | $7.6 \times 10^{-3}$ |
| Ethylbenzene | $3.26 \times 10^{-2}$ | 0.068 | 0.6 |
| Formaldehyde | $3.67 \times 10^{-1}$ | 0.76 | 6.3 |
| Hexane | $2.59 \times 10^{-1}$ | 0.54 | 4.5 |
| Naphthalene | $1.66 \times 10^{-3}$ | 0.0034 | $2.8 \times 10^{-2}$ |
| Other PAHs[4] | $1.79 \times 10^{-4}$ | 0.0004 | $3.1 \times 10^{-3}$ |
| Propylene[2] | $7.71 \times 10^{-1}$ | 1.60 | 13.3 |
| Propylene Oxide | $2.98 \times 10^{-2}$ | 0.006 | 0.5 |
| Toluene | $1.33 \times 10^{-1}$ | 0.28 | 2.3 |
| Xylene | $6.53 \times 10^{-2}$ | 0.14 | 1.1 |
| **Total HAPs** | | | **16.2** |

Notes:
1. See Appendix A, Table A-8 for source of emission factors and basis of calculations.
2. Ammonia and propylene are not HAPs.
3. Ammonia emissions calculated from 10 ppm ammonia slip rate.
4. Includes benzo(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, and indeno(1,2,3-cd)pyrene

8. Commissioning Emissions

Based on a review of commissioning experiences at other large turbine projects, PG&E is proposing changes in some of the emission limits for the commissioning period in the ATC. The current permit limits and the proposed new limits are shown in Table 9 below.

**Table 9**
**Emission Limits for the Commissioning Period**

| | Current Limits | | Proposed Limits | |
|---|---|---|---|---|
| Pollutant | lb/day | lb/hr | lb/day | lb/hr |
| NOx | 8,400 | 400 | no change | no change |
| CO | 13,000 | 584 | 40,000 | 4,000 |
| POC | 535 | --[1] | 1,600 | -- |
| $PM_{10}$ | 624 | -- | 432 | -- |
| $SO_2$ | 297 | -- | no change | -- |

Note:
1. No limit in current permit.

## PART II. DEMONSTRATION OF REGULATORY COMPLIANCE

This section summarizes the applicable BAAQMD rules and regulations and describes how the proposed modification will comply with these requirements.

### A. Regulation 2, Rule 2: New Source Review

The new source review requirements that are applicable to the proposed modification are:

- Best Available Control Technology (BACT) requirements (Rule 2-2-301);
- Offset requirements (Rules 2-2-302 and 2-2-303); and
- Ambient air quality impact analysis (Rule 2-2-305.2).

PSD air quality analysis requirements (Rule 2-2-305.2) are applicable because the CO emissions increases resulting from the proposed modifications will be above the PSD *de minimis* level (see Section III).

#### 1. Best Available Control Technology

Rule 2-2-301 requires the application of BACT to an emissions unit with emissions in excess of 10 pounds per day. Table 10 compares the emissions from the gas turbines/HRSGs to the 10 lb/day threshold and shows the corresponding BACT determinations.

**Table 10**
**Applicability of BACT to the Gas Turbines/HRSGs**

| Pollutant | Emissions per Train, lb/day | BACT |
|---|---|---|
| NOx | 873.3 | SCR (2.0 ppmc, 1-hour avg) |
| $SO_2$ | 142.0 | natural gas fuel |
| CO | 5,732.8 | oxidation catalyst (4.0 ppmc, 3-hour avg) |
| POC | 191.3 | oxidation catalyst (2.0 ppmc, 3-hour avg) |
| $PM_{10}$ | 288.0 | natural gas fuel |

The District made BACT determinations for the facility when the Authority to Construct was issued in 2001, and PG&E has reviewed the current BACT requirements that would be applicable were the facility to be permitted now. While the control technology proposed for the original permit still constitutes BACT, the NOx and the CO emission concentration levels considered to be BACT have been reduced. GGS is proposing to reduce the permitted hourly

NOx and CO emission concentrations and mass emission rates during normal operation to reflect current BACT.

As shown in Tables 4 and 5, emissions from the natural gas-fired dewpoint heater and the Diesel fire pump engine will be less than 10 lb/day, so these units are not subject to BACT requirements.

2. Offset Requirements

Rule 2-2-302 requires POC and NOx emission reduction credits to be provided for facilities that will emit 10 tons per year or more. If the facility will emit 35 tons per year or more on a pollutant-specific basis, the offsets must be provided at a ratio of 1.15:1.0. Offsets must be provided at a ratio of 1.0:1.0 if emissions are between 10 and 35 tons per year.

Rule 2-2-303 requires emissions offsets for emissions increases at facilities that emit more than 100 tons per year of $SO_2$ and $PM_{10}$. If required, these offsets must be provided at a ratio of 1.0:1.0.

Table 11 below summarizes the offset requirements for the proposed modification. The table shows the facility emissions after the modifications, the offset requirements under Rules 2-2-302 and 2-2-303, the offsets provided for the original application, and the remaining offsets required.

**Table 11**
**Summary of Offset Requirements**

| Pollutant | Total Facility Emissions (tpy) | Offset Ratio | Total Offsets Required (tpy) | Offsets Provided for CC8 | Offsets to be Refunded (tpy) |
|---|---|---|---|---|---|
| NOx | 174.3 | 1.15:1.0 | 200.5 | 200.5[1] | 0 |
| POC | 46.6 | 1.15:1.0 | 53.6 | 53.6[1] | 0 |
| $PM_{10}$ | 101.7 | 1.0:1.0 | 101.7 | 112.2[2] | 10.5 |

Notes:
1. NOx and POC ERCs from Banking Certificate #693 (Gaylord Container, Antioch).
2. $PM_{10}$ offsets were provided in the form of $SO_2$ ERCs at a ratio of 3:1. The $SO_2$ ERCs were from Banking Certificates #693 (Gaylord Container, Antioch), #694 (PG&E, Martinez) and #695 (Hudson ICS, San Leandro).

3. Ambient Air Quality Modeling Requirements

Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.2 and 2-2-305.2), a major modification to a major facility must perform modeling to assess the net air quality impact of that pollutant, if the cumulative increase minus the contemporaneous emission reduction credits at the facility exceed maximum annual

pollutant emissions in excess of the trigger levels shown in Table 12. Under Regulation 2-2-605.4, the baseline emission rate used to determine the contemporaneous emission reduction credits is equal to the emission cap that has been fully offset by the facility.

**Table 12**
**Comparison of GGS Cumulative Emissions Increase with PSD Trigger Levels**

| | Emissions, tons per year | | | |
|---|---|---|---|---|
| Pollutant | GGS Proposed Emissions | CC8 Emissions, as permitted and fully offset[1] | Net Increase (Decrease) | PSD Trigger |
| NOx | 174.3 | 174.3 | -- | 40 |
| $SO_2$ | 37.0 | 0[2] | 37.0 | 40 |
| CO | 555.1 | 0[2] | 555.1 | 100 |
| POC | 46.6 | 46.6 | -- | 40 |
| $PM_{10}$ | 101.7 | 112.2 | (10.5) | 15 |

Notes:
1. From Table C-1 of the FDOC.
2. No offsets were required or provided for $SO_2$ and CO emissions from CC8.

Since the cumulative increases in CO emissions exceed the PSD trigger level of 100 tpy, an ambient air quality impact analysis must be performed for CO. The required ambient air quality impacts analysis is provided in Part III of this application.[3]

## B. Screening Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the proposed project. In accordance with the requirements of the Reg. 2, Rule 5 (Toxics New Source Review) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

The screening health risk assessment prepared for the CC8 project showed that the carcinogenic and chronic risks from the project as approved would be below significant impact thresholds. While PG&E proposes to increase allowable annual ammonia emissions from the CTGs and HRSGs by increasing the allowable ammonia slip from 5 ppm to 10 ppm, the original screening health risk assessment was based on 10 ppm ammonia slip so the proposed change will not affect

[3] Because this amendment includes increases in short-term NOx emissions during commissioning, the ambient air quality impact analysis also includes an evaluation of short-term $NO_2$ impacts from the project.

that conclusion. In fact, by eliminating the wet cooling tower, the potential health risk from the project would be reduced. However, since the proposed modifications to the approved facility include the addition of a Diesel fire pump engine and Diesel particulate matter (DPM) is considered a toxic air contaminant, a new screening health risk assessment has been prepared that includes the Diesel fire pump engine. The results of the revised screening health risk assessment are presented in Table 13. A detailed discussion of the screening health risk assessment procedures and assumptions is provided in Appendix C to this application.

**Table 13**
**Screening Health Risk Assessment Results**

| Source | Carcinogenic Risk (in one million) | Chronic Health Hazard Index | Acute Health Hazard Index |
|---|---|---|---|
| Gas Turbines and HRSGs, Dewpoint Heater | 0.16 | 0.01 | 0.09 |
| Diesel Fire Pump Engine | 0.96 | <0.01 | n/a |
| Total, All Sources | 1.04 | 0.01 | 0.09 |

The maximum cancer risk from the facility, which is due mainly to the Diesel particulate matter emissions from the fire pump engine, is slightly higher than 1 in one million. Since the fire pump engine PM emissions comply with the 0.1 g/bhp-hr level considered toxics BACT (T-BACT), the risk is considered acceptable. In addition, the area where the cancer risk is predicted to exceed 1 in one million is limited to receptors at the southeast fenceline of the plant property.

## C. Other District Rules and Regulations

In the Final Determination of Compliance issued for CC8 in February 2001, the District staff determined that the facility would comply with all other applicable District rules and regulations. The proposed modifications in this application do not change the District's conclusions regarding the applicable rules and regulations or the compliance of the gas turbines, HRSGs and dewpoint heater. The compliance of the facility, including the proposed Diesel fire pump engine, is summarized in this section.

### 1. Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis insures that the proposed facility will comply with this Regulation.

2. Regulation 2, Rule 1, Sections 301 and 302: Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, PG&E has submitted an application to the District to obtain a modified Authority to Construct and Permit to Operate for the proposed S-41 & S- 43 Gas Turbines, S-42 & S-44 Heat Recovery Steam Generators, S-45 Fuel Preheater, S-48 Oil Water Separator and S-50 Diesel Fire Pump Engine.

3. Regulation 2, Rule 3: Power Plants

Because the GGS has already received its license from the California Energy Commission, the District's review does not fall under the requirements of Regulation 2, Rule 3.

4. Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, PG&E has submitted a Major Facility Review application for the facility as originally permitted. An amended MFR permit application will be submitted to reflect the modifications proposed in this application.

5. Regulation 2, Rule 7: Acid Rain

The GGS gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), GGS must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. The required Acid Rain Permit Application was submitted to the District and to EPA in December 2006.

6. Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NOx burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines and HRSG duct burners is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. In the DOC for the original project, the District staff determined that the grain loading resulting from the simultaneous operation of each power train would comply with the grain loading limit. Since PG&E is proposing to reduce the $PM_{10}$ emissions from the gas turbines and HRSGs during duct firing, the compliance margin will be even greater.

7. Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the two proposed CTG/HRSG power trains will each be limited by permit condition to 10 ppmvd @ 15% $O_2$, the facility is expected to comply with the requirements of Regulation 7.

8. Regulation 8: Organic Compounds

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively in the GGS gas turbines and duct burners.

9. Regulation 9: Inorganic Gaseous Pollutants

- Regulation 9, Rule 1, Sulfur Dioxide
- Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations
- Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters
- Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

The DOC for the original project made the determination that the project was in compliance with or exempt from these rules. No changes to the project are being proposed that would affect these determinations.

## D. Other Federal Requirements

1. New Source Performance Standards

The federal new source performance standards (NSPS) establish standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established national ambient air quality standards [NAAQS]) from new or modified facilities in specific source categories. The NSPS for Stationary Gas Turbines and for Stationary Compression Ignition Internal Combustion Engines will be applicable to the proposed project.

When the project was originally permitted, the gas turbines were subject to the requirements of Subpart GG. However, since the facility did not commence construction as defined under the NSPS before February 18, 2005, the requirements of Subpart KKKK are now applicable.[4]

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[4] The previous owner of the project, Mirant, commenced construction under a valid ATC in 2001, but suspended construction in 2002. Because substantial use had been made of the ATC, the BAAQMD renewed the ATC in accordance with Rule 2-1-407.3. However, the NSPS defines "commence" as "undertak[ing] a continuous program of construction…or…entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction…" (40 CFR 60.2) A suspension in construction of longer than 18 months is generally used by EPA to determine that construction has not been continuous.

Subpart KKKK limits NOx and SO2 emissions from new gas turbines based on power output. The limits for gas turbines greater than 30 MW are 0.39 lb NOx per MW-hr and 0.58 lb SO2 per MW-hr. The emission limits of 2.0 ppmc NOx and 0.56 ppmc SO2 proposed for GGS are well below the Subpart KKKK limits, as shown in Table 14.

**Table 14**
**Compliance With 40 CFR 60 Subpart KKKK**

| Pollutant | Proposed Permit Limits | | | Subpart KKKK Limit, lb/MW-hr |
|---|---|---|---|---|
| | ppmc | lb/hr | lb/MW-hr (max) | |
| NOx | 2.0 | 15.2 | 0.08 | 0.39 |
| $SO_2$ | 0.56 | 5.9 | 0.03 | 0.59 |

Compliance with the NSPS limits must be demonstrated through an initial performance test. Because the GGS gas turbines will be equipped with continuous NOx emissions monitors, ongoing annual performance testing will not be required under the NSPS.

For the size of engine proposed for the emergency fire pump engine, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, requires facilities to purchase engines meeting the EPA engine non-road certification level of Tier II or better depending on the year the engine is manufactured/purchased. This regulation also requires the engines to use ultra-low sulfur content Diesel fuel.

2. National Emissions Standards for Hazardous Air Pollutants

The calculations in Section 1.D. of this application demonstrate that emissions of HAPs from the facility will be well below the major source thresholds of 10 tons per year of individual HAP or 25 tons per year of total HAPs. Therefore, the facility is not subject to the MACT requirements of the National Emissions Standards for Hazardous Air Pollutants.

## Part III. PSD Ambient Air Quality Impact Analysis

As shown in Table 14 above, the cumulative increases in emissions from the proposed changes are below the PSD significant emissions thresholds for all pollutants except CO. Since the net increase in emissions of this pollutant exceeds the applicable significance threshold, a revised ambient air quality analysis is required for CO. Because changes are being proposed to the emission rates during gas turbine startup and commissioning, new startup modeling has also been carried out.

### A. Air Quality Modeling Methodology

The assessment of impacts from GGS on ambient air quality has been conducted using the EPA guideline models SCREEN3 and AERMOD and three years of surface meteorological data (2004 through 2006) collected by Mirant at the Contra Costa power plant less than ½ mile from the project site.[5] Upper air data were obtained from Buchanan Field in Concord.[6] The ambient air quality impact analysis was conducted in accordance with the protocol filed with the District in August 2007 and the comments provided by the District staff in October 2007 (see Appendix B, Attachment B-1).The surface parameters developed for use in the AERMET meteorological data input are documented in Appendix B, Attachment B-2. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Impacts were evaluated in simple and complex terrain and under inversion breakup and shoreline fumigation conditions. The PV Molar Ratio Method was used to convert one-hour NOx impacts into one-hour $NO_2$ impacts. Figure 1 shows the layout of the facility and the location of each exhaust stack. Building dimensions used in the BPIP analysis are summarized in Table B-1 of Appendix B, and are shown in detail in the modeling files provided.

Emissions from the turbines will be exhausted from two 195-foot exhaust stacks. The project also includes emissions from the dewpoint heater with a release height of approximately 15 feet,

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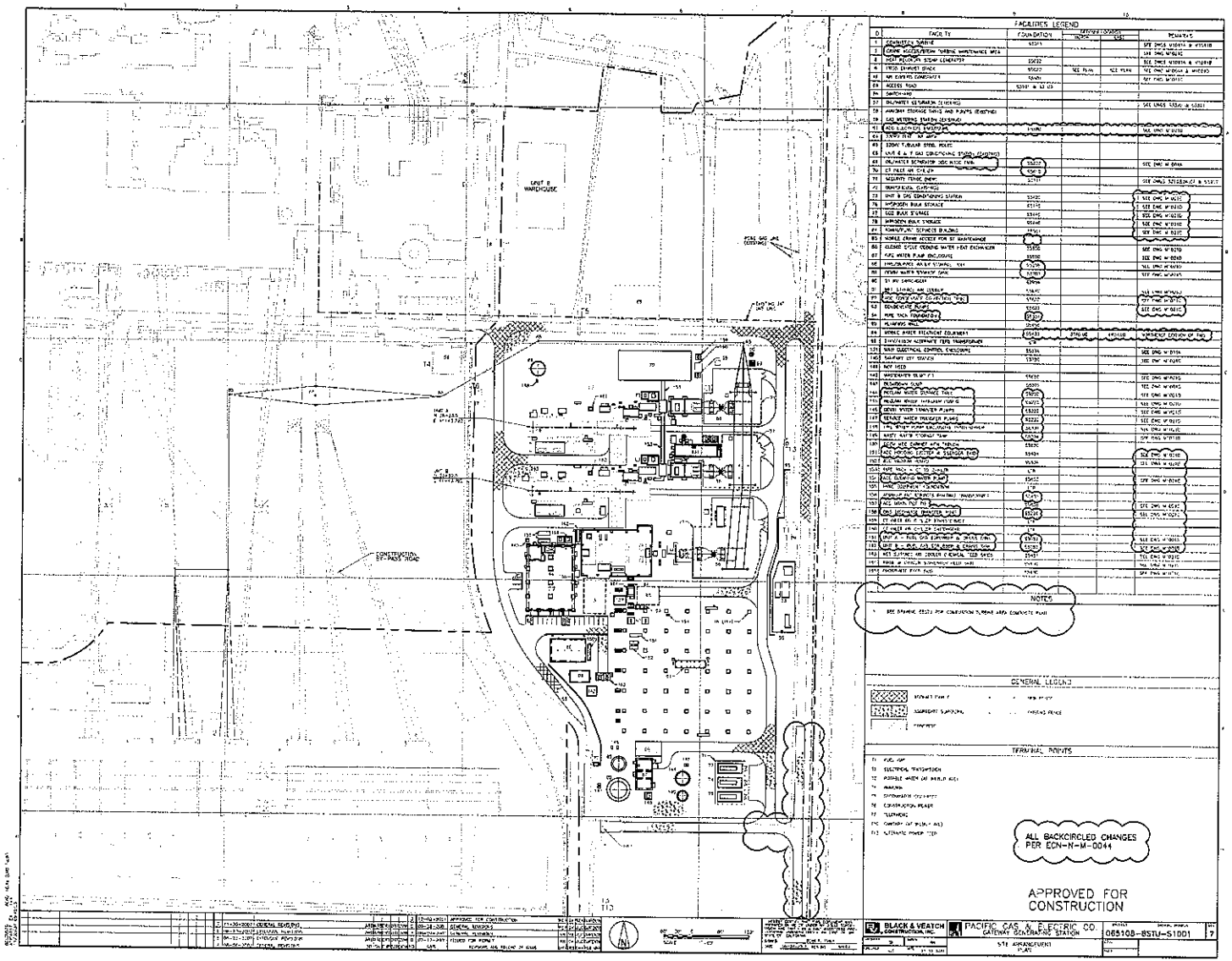
[5] The original AQIA for CC8 was carried out using ISCST3. Since that time, EPA has adopted AERMOD as a guideline model to replace ISCST3.

[6] Although BAAQMD policy to limit mixing height to 600 meters, it is not possible to impose this limit in the AERMOD modeling system.

**Figure 1**
**Facility Layout**



the wet surface air cooler with a release height of approximately 19 feet, and the small Diesel fire pump engine with a release height of 10 feet 8 inches.[7]

## B. Air Quality Impact Analysis

### 1. Screening Analysis for Turbines/HRSGs

The original permit application had identified 11 different likely operating conditions for the turbines and HRSGs that reflect a range of operating temperatures and loads, with and without the duct burners in operation. With the elimination of PAG and modifications to the duct firing capability of the units, the 11 operating conditions have been reduced to eight conditions, which are summarized below in Table 15. Emission rates and stack parameters for these operating conditions are shown in Appendix B, Table B-2.

**Table 15**
**Turbine Operating Conditions for Screening Analysis**

| Condition Number | Turbine Load | Ambient Temp, deg. F | Duct Firing? | Inlet Air Chilling? |
|---|---|---|---|---|
| 1 | 100% | 30 | no | no |
| 2 | 50% | 30 | no | no |
| 3 | 100% | 60 | no | yes |
| 4 | 50% | 60 | no | yes |
| 5 | 100% | 60 | yes | yes |
| 6 | 100% | 100 | no | yes |
| 7 | 50% | 100 | no | yes |
| 8 | 100% | 100 | yes | yes |

To ensure that impacts were evaluated under the operating conditions that produced the highest ambient impacts, a screening procedure was used to determine the inputs to the refined modeling. These operating cases were screened for worst-case ambient impacts on a pollutant- and averaging period-specific basis using the AERMOD model and the meteorological data described above. The results of the turbine screening analysis are presented in Appendix B, Table B-3, and are summarized in Table 16. The stack parameters and emissions rates for the turbine operating condition that produced the maximum modeled impact for each pollutant and averaging period were then used in the refined modeling analysis to evaluate the modeled impacts of the project

[7] Although the WSAC is exempt from District permitting, it has been included in the AQIA for completeness.

| Table 16<br>Results of Turbine Screening Procedure:<br>Turbine Operating Conditions Producing Maximum Modeled Ambient Impacts by Pollutant and Averaging Period | | |
|---|---|---|
| Pollutant/Averaging Period | | Operating Case |
| NOx and CO | 1 hour (startup only) | Case 4 |
| NOx, CO, $SO_2$ and $PM_{10}$ | 1, 3 and 8 hours<br>24 hours ($SO_2$ only) annual | Case 5 |
| $PM_{10}$ | 24 hours | Case 7 |

for that pollutant and averaging period. Although only short-term $NO_2$ and CO impacts are required to be evaluated, all pollutants and averaging times have been included in the AQIA.

The screening analysis included both simple and complex terrain and accounted for downwash conditions at the facility. Terrain features were taken from USGS DEM data and 7.5-minute quadrangle maps of the area. For the turbine screening analysis, the coarse Cartesian grids of receptors from the original analysis were used.

2. Refined Air Quality Impact Analysis

The operating conditions and emission rates used to model GGS are shown in Table B-4, Appendix B. As discussed above, the turbine stack parameters used in modeling the impacts for each pollutant and averaging period reflected the worst-case screening analysis.

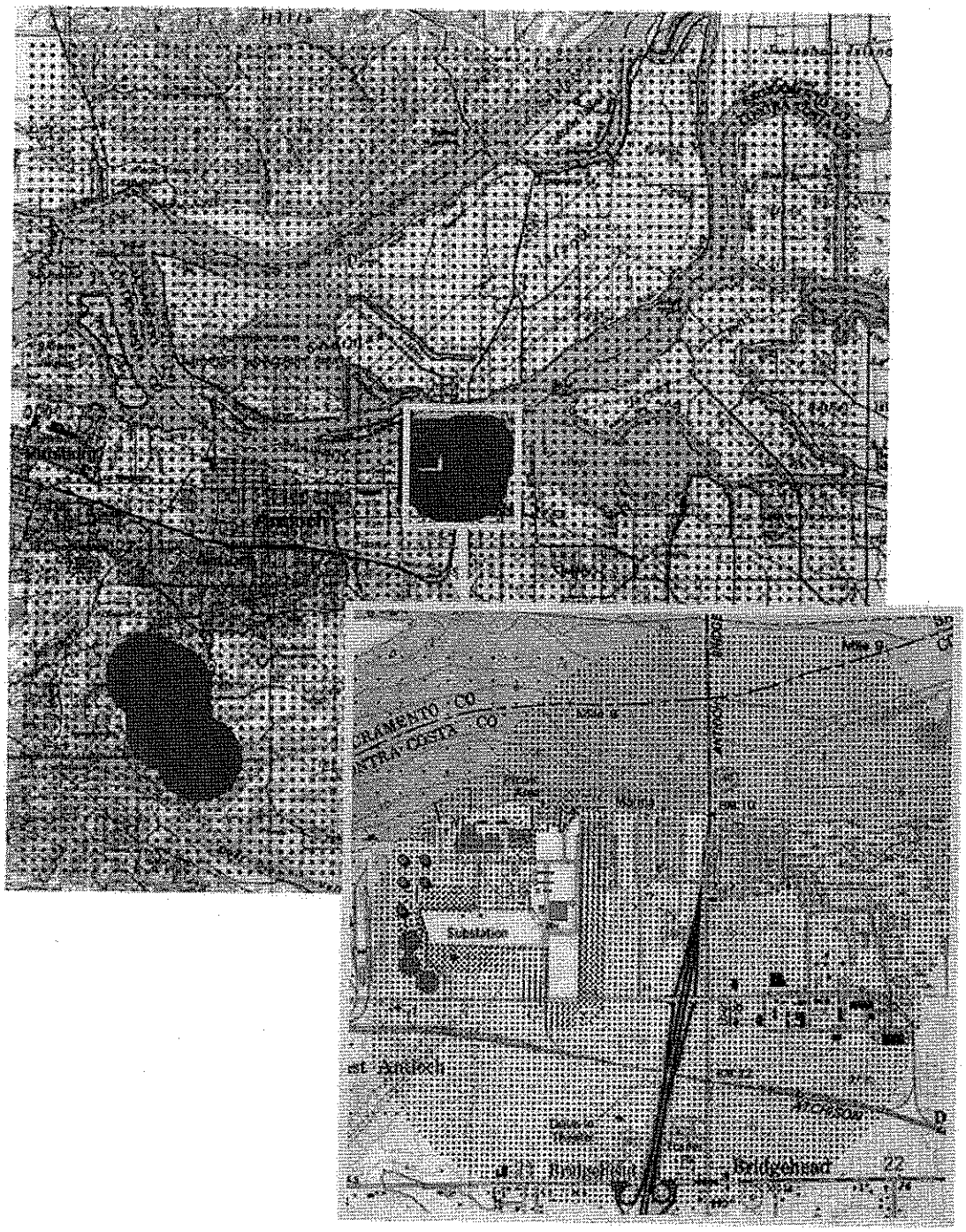
The receptor grids were derived from 7.5 minute DEM data. Twenty-five by 25 meter refined receptor grids were used in areas where the coarse grid analysis indicated modeled maxima would be located. Figure 2 shows the layout of the receptor grid.

Emissions from the permitted units were also modeled under inversion breakup fumigation and shoreline fumigation conditions, as well as during startup and commissioning, to ensure that the worst-case impacts are evaluated. These specialized air quality modeling analyses are discussed in more detail below.

**Inversion Breakup Fumigation**

Fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may be drawn to the ground, causing high ground-level pollutant concentrations. Although fumigation conditions rarely last as long as one hour, relatively high ground-level concentrations may be reached during that time.

**Figure 2**
**Layout of the Receptor Grid**




The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Since SCREEN3 is a single-source model, each source was modeled separately and the maximum modeled concentrations were added together regardless of

their locations. This approach is believed to overestimate the predicted concentrations under inversion breakup fumigation conditions.

Calculation of inversion breakup fumigation impacts is shown in Appendix B, Table B-5.

**Shoreline Fumigation Modeling**

Shoreline fumigation modeling was conducted to determine the impacts as a result of overwater plume dispersion. Because land surfaces tend to both heat and cool more rapidly than water, shoreline fumigation tends to occur on sunny days when the denser cooler air over water displaces the warmer, lighter air over land. During an inland sea breeze, the unstable air over land gradually increases in depth with inland distance. The boundary between the stable air over the water and the unstable air over the land and the wind speed determine if the plume will loop down before much dispersion of the pollutants has occurred. SCREEN3 can examine sources within 3000 meters of a large body of water, and was used to calculate the maximum shoreline fumigation impact. The model uses a stable onshore flow and a wind speed of 2.5 meters per second; the maximum ground-level shoreline fumigation concentration is assumed by the model to occur where the top of the stable plume intersects the top of the well-mixed thermal inversion boundary layer (TIBL). The model TIBL height was varied in accordance with BAAQMD procedures (between 2 and 6) to determine the highest shoreline fumigation impact. The worst-case (highest) impact was used in determining facility impacts due to shoreline fumigation. Based on the analysis performed for the original CC8 project, shoreline fumigation was assumed to persist for a maximum of 180 minutes, and the impacts on all short-term averaging periods were assessed. Calculation of shoreline fumigation impacts is shown in Appendix B, Table B-6.

**Turbine Startup**

Facility impacts were also modeled during the startup of one turbine to evaluate short-term impacts under startup conditions. Emission rates during startup were based on an engineering analysis of available data, which included source test data from startups of the GE gas turbines at Los Medanos Energy Center and Moss Landing Power Plant. Turbine exhaust parameters for the minimum operating load point (50%) were used to characterize turbine exhaust during startup. Startup impacts were evaluated for the 1-hour averaging period using AERMOD.[8] Calculation of startup impacts is shown in more detail in Appendix B, Table B-7.

**Turbine Commissioning**

During commissioning, one or both of the CTGs may operate without emission controls while the CTGs and HRSGs are being tuned and tested. Commissioning impacts were evaluated for both the 1- and 8-hour averaging periods using AERMOD. Calculation of commissioning impacts is shown in more detail in Appendix B, Table B-8.

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[8] Modeling for CO impacts for the 8-hour averaging period include startup.

3. Results of the Ambient Air Quality Modeling Analysis

The maximum facility impacts modeled for each of the analyses described above are summarized in Table 17 below. Highest 1-hour average $NO_2$ and CO impacts are expected to occur during the brief periods when the fire pump is being tested.

**Table 17**
**Summary of Results from Refined Modeling Analysis for Permitted Sources**

| Pollutant | Averaging Time | Modeled Concentration ($\mu g/m^3$) | | | |
|---|---|---|---|---|---|
| | | Normal Operation[1] | Inversion Breakup Fumigation[2] | Shoreline Fumigation[2] | Startup |
| $NO_2$ | 1 hour | 146.8 | 6.3 | 40.3 | 104.9 |
| | annual | 3.4 | n/a | n/a | n/a |
| $SO_2$ | 1 hour | 9.8 | 2.4 | 15.7 | n/a |
| | 3 hours | 4.8 | 2.2 | 14.1 | n/a |
| | 24 hours | 1.0 | 1.0 | 1.6 | n/a |
| | annual | 0.12 | n/a | n/a | n/a |
| CO | 1 hour | 51.4 | 7.7 | 49.1 | 926 |
| | 8 hours | 292.5 | 5.4 | 16.2 | n/a[3] |
| $PM_{10}$ | 24 hours | 4.0 | 2.3 | 3.9 | n/a |
| | annual | 1.4 | n/a | n/a | n/a |

Notes:
1. Includes fire pump. Without fire pump, maximum 1-hour average $NO_2$ concentration is 68 $ug/m^3$.
2. Inversion breakup and shoreline fumigation are short-term phenomena and do not affect annual impacts.
3. Included in 8-hour impacts for normal operations.

## C. Total Ambient Air Quality Impacts

The maximum facility impacts including the exempt sources are summarized in Table 18 below. To determine the maximum ground-level impacts on ambient air quality for comparison with the applicable state and federal ambient air quality standards, modeled worst-case impacts were added to maximum existing pollutant concentrations in the area. Maximum ground-level impacts for allowable operation of the facility are shown together with the ambient air quality standards in Table 18.

**Table 18**
**Modeled Maximum Project Impacts[1]**

| Pollutant | Averaging Time | Maximum Facility Impact[1] ($\mu g/m^3$) | Background[2] ($\mu g/m^3$) | Total Impact ($\mu g/m^3$) | State Standard ($\mu g/m^3$) | Federal Standard ($\mu g/m^3$) |
|---|---|---|---|---|---|---|
| $NO_2$ | 1 hour | 151.8 | 109 | 260.8 | 338[3] | -- |
| | annual | 3.4 | 20.8 | 24.2 | 56[3] | 100 |
| $SO_2$ | 1 hour | 16 | 117 | 133 | 655 | -- |
| | 3 hours | 14 | 65.0 | 79 | -- | 1300 |
| | 24 hours | 1.6 | 26.3 | 27.9 | 105 | 365 |
| | annual | 0.1 | 5.3 | 5.4 | -- | 80 |
| CO | 1 hour | 926 | 5,125 | 6,051 | 23,000 | 40,000 |
| | 8 hours | 293 | 2,133 | 2,426 | 10,000 | 10,000 |
| $PM_{10}$ | 24 hours | 4.0 | 64.0 | 68 | 50 | 150 |
| | annual | 1.4 | 21.7 | 22.1 | 20 | -- |

Notes:
1. See Note 1, Table 15.
2. Background concentrations reflect highest monitored concentrations from Pittsburg and Bethel Island monitoring stations, 2004-2006.
3. The ARB amended the Nitrogen Dioxide ambient air quality standard February 22, 2007, to lower the 1-hr standard to 0.18 ppm and establish a new annual standard of 0.030 ppm. These changes will become effective after regulatory changes are submitted and approved by the Office of Administrative Law.

# Appendix A

## Emissions Calculations

**Table A-1**
**Gateway Generating Station**
**Emissions and Operating Parameters for CTGs**

| Case | Cold Base | Cold Low | Avg. Base | Avg. Low | Avg. Peak | Hot Base | Hot Low | Hot Peak |
|---|---|---|---|---|---|---|---|---|
| Turbine Load, MW | 192.7 | | 181.4 | | 181.4 | 181.4 | | 181.4 |
| Ambient Temp, F | 30 | 30 | 60 | 60 | 60 | 100 | 100 | 100 |
| Turbine Load, % | | | | | | | | |
| Chiller On/Off | Off | Off | On | On | On | On | On | On |
| CTG heat input, MMBtu/hr (HHV | 1848.1 | 1209.0 | 1848.1 | 1271.9 | 1848.1 | 1848.1 | 1114.0 | 1848.1 |
| DB heat input, MMBtu/hr (HHV) | 0.0 | 0.0 | 0.0 | 0.0 | 246.3 | 0.0 | 0.0 | 246.3 |
| Total heat input, MMBtu/hr (HHV | 1848.1 | 1209.0 | 1848.1 | 1271.9 | 2094.4 | 1848.1 | 1114.0 | 2094.4 |
| Stack flow, lb/hr | 3,371,393 | 2,205,562 | 3,391,353 | 2,334,098 | 3,120,398 | 3,446,840 | 2,077,733 | 3,171,163 |
| Stack flow, acfm | 928,011 | 607,104 | 936,640 | 644,642 | 865,245 | 960,629 | 579,061 | 887,192 |
| Stack flow, dscfm | 689,649 | 451,167 | 689,649 | 474,650 | 624,466 | 689,649 | 415,716 | 624,466 |
| Stack temp, F | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 |
| Stack exhaust, vol % | | | | | | | | |
| O2 (dry) | 13.00% | 13.00% | 13.00% | 13.00% | 11.00% | 13.00% | 13.00% | 11.00% |
| CO2 (dry) | 4.52% | 4.52% | 4.52% | 4.52% | 5.65% | 4.52% | 4.52% | 5.65% |
| H2O | 8.54% | 8.54% | 9.38% | 9.38% | 11.17% | 11.64% | 11.64% | 13.37% |
| Emissions | | | | | | | | |
| NOx, ppmvd @ 15% O2 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| NOx, lb/hr | 13.40 | 8.76 | 13.40 | 9.22 | 15.18 | 13.40 | 8.08 | 15.18 |
| NOx, lb/MMBtu | 0.0072 | 0.0072 | 0.0072 | 0.0072 | 0.0072 | 0.0072 | 0.0072 | 0.0072 |
| SO2, ppmvd @ 15% O2 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 |
| SO2, lb/hr (short-term) | 5.22 | 3.42 | 5.22 | 3.59 | 5.92 | 5.22 | 3.15 | 5.92 |
| SO2, lb/MMBtu (short-term) | 0.0028 | 0.0028 | 0.0028 | 0.0028 | 0.0028 | 0.0028 | 0.0028 | 0.0028 |
| SO2, lb/hr (long-term) | 3.92 | 2.56 | 3.92 | 2.69 | 4.44 | 3.92 | 2.36 | 4.44 |
| SO2, lb/MMBtu (long-term) | 0.0021 | 0.0021 | 0.0021 | 0.0021 | 0.0021 | 0.0021 | 0.0021 | 0.0021 |
| CO, ppmvd @ 15% O2 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 |
| CO, lb/hr | 16.31 | 10.67 | 16.31 | 11.23 | 18.49 | 16.31 | 9.83 | 18.49 |
| CO, lb/MMBtu | 0.0088 | 0.0088 | 0.0088 | 0.0088 | 0.0100 | 0.0088 | 0.0088 | 0.0100 |
| POC, ppmvd @ 15% O2 | 2.00 | 2.00 | 2.00 | 2.00 | 1.60 | 2.00 | 2.00 | 2.00 |
| POC, lb/hr | 4.67 | 3.06 | 4.67 | 3.22 | 4.23 | 4.67 | 2.82 | 5.29 |
| POC, lb/MMBtu | 0.0025 | 0.0025 | 0.0025 | 0.0025 | 0.0023 | 0.0025 | 0.0025 | 0.0029 |
| PM10, lb/hr | 11.0 | 11.0 | 11.0 | 11.0 | 12.0 | 11.0 | 11.0 | 12.0 |
| PM10, lb/MMBtu | 0.0060 | 0.0091 | 0.0060 | 0.0086 | 0.0065 | 0.0060 | 0.0099 | 0.0065 |
| PM10, gr/dscf | 0.00186 | 0.00284 | 0.00186 | 0.00270 | 0.00224 | 0.00186 | 0.00309 | 0.00224 |
| NH3, ppmvd@15% O2 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| NH3, lb/hr | 24.80 | 16.22 | 24.80 | 17.07 | 28.10 | 24.80 | 14.95 | 28.10 |

**Table A-2**
**Gateway Generating Station**
**Calculation of Wet SAC Emissions**

| Typical Worst-Case Design Parameters | |
|---|---|
| Water Flow Rate, 10E6 lbm/hr | 2.59 |
| Water Flow Rate, gal/min | 5,180 |
| Drift Rate, % | 0.0030 |
| Drift, lbm water/hr | 77.67 |
| PM10 Emissions based on TDS Level | |
| TDS level, ppm (based on 5 COC) | 2500 |
| PM10, lb/hr | 0.19 |
| PM10, lb/day | 4.7 |
| PM10, tpy | 0.85 |

Based on 8760 hrs/yr

**Table A-3**
**Gateway Generating Station**
**Emissions for Dewpoint Heater**

| | |
|---|---|
| Fuel Gas Flow, MMBtu/hr (HHV) | 6.5 |
| Fuel Gas Flow, scfh | 6418 |
| Exhaust Flow Rate, acfm | 1964 |
| Stack Gas Temperature, deg F | 300 |
| Stack Diameter, inches | 7.981 |
| | |
| Emissions | |
| NOx, ppmvd @ 3% O2 (1) | 50 |
| NOx, lb/MMBtu (HHV) (1) | 0.060 |
| CO, ppmvd @ 3% O2 (1) | 40 |
| CO, lb/MMBtu (HHV) (1) | 0.029 |
| POC, ppmvd @ 3% O2 (1) | 5.5 |
| POC, lb/MMBtu (HHV) (1) | 0.0045 |
| PM10, lb/MMBtu (HHV) (1) | 0.0074 |
| SO2, lb/MMscf (3) | 2.86 |
| | |
| NOx, lb/hr (2) | 0.392 |
| CO, lb/hr (2) | 0.191 |
| POC, lb/hr (2) | 0.029 |
| PM10, lb/hr | 0.048 |
| SO2, lb/hr | 0.018 |

Notes:
1. Manufacturer specification at rated heater capacity.
2. Manufacturer guarantee
3. Calculated from sulfur content of natural gas (<1 gr/100 scf)

**Table A-4**
**Gateway Generating Station**
**Diesel Fire Pump Performance and Emissions**

| | | |
|---|---|---|
| **Engine** | | |
| Fire Pump Mfr | | Clarke |
| Engine Mfr | | John Deere |
| Model | | JU6H-UF40 |
| Useable Horsepower | hp | 300 |
| Speed | rpm | 2100 |
| Fuel | | CA Diesel |
| Specific Gravity | | 0.825 |
| Fuel Sulfur Content | wt % | 0.0015% |
| Fuel Consumption | gph | 14 |
| | Btu/bhp-hr | 0 |
| Exhaust Flow | acfm | 1740 |
| Stack Velocity | ft/sec | 13.4 |
| Exhaust Temperature | deg. F | 770 |
| Exhaust Pipe Diameter | in | 6.065 |
| Exhaust Stack Height | ft | 10.67 |
| **Pump** | | |
| Speed | rpm | 2100 |
| Capacity | gpm | 2500 |
| Pump Efficiency | % | 74 |
| Brake Horsepower | bhp | 300 |
| **Operating Profile** | | |
| Annual Operation | hrs | 50 |
| **Emissions** | | |
| | g/bhp-hr | lb/hr |
| NOx | 4.36 | 2.88 |
| CO | 0.32 | 0.21 |
| ROC | 0.29 | 0.19 |
| PM10 | 0.12 | 0.08 |
| SO2 | -- | 0.0029 |

| | |
|---|---|
| Diesel fuel | 7.00 lb/gal |
| | 136,903 Btu/gal |

Table A-5
Gateway Generating Station
Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

| Assumptions for Daily and Annual Ops: | Startup/ Shutdown Hours | Duct Firing Hours | Base Load Hours | |
|---|---|---|---|---|
| NOx, POC, CO | 6 | 18 | 0 | per day |
| CO | 520 | 4380 | 324 | per year |
| NOx, POC | 365 | 5840 | 1825 | per year |
| SOx, PM10 | 0 | 24 | 0 | per day |
| | 0 | 5100 | 3660 | per year |

| Equipment | max. hour | NOx (lbs/hr) | SOx (lbs/hr) short-term | SOx (lbs/hr) annual avg | CO (lbs/hr) | POC (lbs/hr) | PM10 (lbs/hr) | NH3 (lbs/hr) |
|---|---|---|---|---|---|---|---|---|
| Gas Turbine 1, base | 0 | 13.40 | 5.22 | 3.92 | 16.31 | 4.67 | 11.00 | 24.80 |
| Gas Turbine 2, base | 0 | 13.40 | 5.22 | 3.92 | 16.31 | 4.67 | 11.00 | 24.80 |
| Gas Turbine 1, peak | 1 | 15.18 | 5.92 | 4.44 | 18.49 | 5.29 | 12.00 | 28.10 |
| Gas Turbine 2, peak | 0 | 15.18 | 5.92 | 4.44 | 18.49 | 5.29 | 12.00 | 28.10 |
| Gas Turbine 1, startups/shutdowns | 0 | 100.00 | 5.22 | n/a | 900.00 | 16.00 | 11.00 | 24.80 |
| Gas Turbine 2, startups/shutdowns | 1 | 100.00 | 5.22 | n/a | 900.00 | 16.00 | 11.00 | 24.80 |
| Dewpoint Heater | 1 | 0.39 | 1.83E-02 | 1.38E-02 | 0.19 | 0.03 | 0.05 | 0 |
| WSAC | 1 | 0.00 | 0.00 | n/a | 0.00 | 0.00 | 0.19 | 0 |
| Diesel Fire Pump Engine | 1 | 2.88 | 2.94E-03 | n/a | 0.21 | 0.19 | 0.08 | 0 |

Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

| Equipment | NOx Emissions Max lb/hr | NOx Emissions Max lb/day | NOx Emissions Total tpy | SOx Emissions Max lb/hr | SOx Emissions Max lb/day | SOx Emissions Total tpy | CO Emissions Max lb/hr | CO Emissions Max lb/day | CO Emissions Total tpy | POC Emissions Max lb/hr | POC Emissions Max lb/day | POC Emissions Total tpy | PM10 Emissions Max lb/hr | PM10 Emissions Max lb/day | PM10 Emissions Total tpy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gas Turbine 1, base | 0.0 | 0.0 | 12.2 | 0.0 | 0.0 | 7.2 | 0.0 | 0.0 | 2.6 | 0.0 | 0.0 | 4.3 | 0.0 | 0.0 | 20.1 |
| Gas Turbine 2, base | 0.0 | 0.0 | 12.2 | 0.0 | 0.0 | 7.2 | 0.0 | 0.0 | 2.6 | 0.0 | 0.0 | 4.3 | 0.0 | 0.0 | 20.1 |
| Gas Turbine 1, peak | 15.2 | 273.3 | 44.3 | 5.9 | 142.0 | 11.3 | 18.5 | 332.8 | 40.5 | 5.3 | 95.3 | 15.5 | 12.0 | 288.0 | 30.6 |
| Gas Turbine 2, peak | 0.0 | 273.3 | 44.3 | 5.9 | 142.0 | 11.3 | 0.0 | 332.8 | 40.5 | 0.0 | 95.3 | 15.5 | 12.0 | 288.0 | 30.6 |
| Gas Turbine 1, startups/shutdowns | 0.0 | 600.0 | 18.3 | 0.0 | 0.0 | 0.0 | 0.0 | 5,400.0 | 234.0 | 0.0 | 96.0 | 2.9 | 0.0 | 0.0 | 0.0 |
| Gas Turbine 2, startups/shutdowns | 160.0 | 600.0 | 18.3 | 0.0 | 0.0 | 0.0 | 900.0 | 5,400.0 | 234.0 | 16.0 | 96.0 | 2.9 | 0.0 | 0.0 | 0.0 |
| Dewpoint Heater | 0.4 | 9.4 | 1.7 | 1.8E-02 | 0.4 | 0.1 | 0.2 | 4.6 | 0.8 | 2.9E-02 | 0.7 | 0.1 | 0.05 | 1.2 | 0.2 |
| WSAC | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0.2 | 4.7 | 0.9 |
| Diesel Fire Pump Engine | 2.9 | 2.9 | 0.1 | 2.9E-03 | 2.9E-03 | 7.4E-05 | 0.2 | 0.2 | 5.3E-03 | 0.2 | 0.2 | 0.0 | 0.1 | 0.1 | 2.0E-03 |
| Total, CTGs/HRSGs only | 175.2 lb/hr | 1,746.6 lb/day | 149.6 tpy | 11.8 lb/hr | 284.0 lb/day | 36.96 tpy | 918.5 lb/hr | 11,465.6 lb/day | 554.3 tpy | 21.3 lb/hr | 382.6 lb/day | 45.3 tpy | 24.0 lb/hr | 576.0 lb/day | 101.5 tpy |
| Total Permitted Equipment (excluding WSAC) | 178.5 lb/hr | 1,758.9 lb/day | 151.4 tpy | 11.9 lb/hr | 284.4 lb/day | 37.0 tpy | 918.9 lb/hr | 11,470.4 lb/day | 555.1 tpy | 21.5 lb/hr | 383.5 lb/day | 45.4 tpy | 24.1 lb/hr | 577.2 lb/day | 101.7 tpy |
| Proposed Permit (excluding WSAC) | | 1,994.0 lb/day | 174.3 tpy | | 297.0 lb/day | 37.8 tpy | | 11,470.4 lb/day | 555.1 tpy | | 468.0 lb/day | 46.6 tpy | | 624.0 lb/day | 101.7 tpy |
| Existing Permit | | 1,994.0 lb/day | 174.3 tpy | | 297.0 lb/day | 48.5 tpy | | 3,602.0 lb/day | 259.1 tpy | | 468.0 lb/day | 46.6 tpy | | 624.0 lb/day | 112.2 tpy |

**Table A-6**
**Gateway Generating Station**
**Calculation of Noncriteria Pollutant Emissions from Gas Turbines**

| Compound | Emission Factor, lb/MMscf (1) | Maximum Hourly Emissions, lb/hr Each CTG (2) | Total, 2 CTGs | Total Annual Emissions, 2 CTGs (3) lb/yr | tpy |
|---|---|---|---|---|---|
| Ammonia | (4) | 28.10 | 56.21 | 468,197.8 | 234.1 |
| Propylene | 7.71E-01 | 1.60 | 3.19 | 26,588.8 | 13.3 |
| Hazardous Air Pollutants | | | | | |
| Acetaldehyde | 4.08E-02 | 8.44E-02 | 1.69E-01 | 1,407.0 | 0.70 |
| Acrolein | 3.69E-03 | 7.64E-03 | 1.53E-02 | 127.3 | 6.36E-02 |
| Benzene | 3.33E-03 | 6.89E-03 | 1.38E-02 | 114.8 | 5.74E-02 |
| 1,3-Butadiene | 4.39E-04 | 9.09E-04 | 1.82E-03 | 15.1 | 7.57E-03 |
| Ethylbenzene | 3.26E-02 | 6.75E-02 | 1.35E-01 | 1,124.2 | 5.62E-01 |
| Formaldehyde | 3.67E-01 | 0.76 | 1.52 | 12,656.4 | 6.33 |
| Hexane | 2.59E-01 | 0.54 | 1.07 | 8,931.9 | 4.47 |
| Naphthalene | 1.66E-03 | 3.44E-03 | 6.87E-03 | 57.2 | 2.86E-02 |
| PAHs (5) | 4.57E-05 | 9.45E-05 | 1.89E-04 | 1.6 | 7.87E-04 |
| Propylene oxide | 2.98E-02 | 6.17E-02 | 0.12 | 1,027.7 | 0.51 |
| Toluene | 1.33E-01 | 2.75E-01 | 0.55 | 4,586.7 | 2.29 |
| Xylene | 6.53E-02 | 1.35E-01 | 0.27 | 2,251.9 | 1.13 |
| Total HAPs | | | 3.88 | 32,302.0 | 16.15 |

Notes:

(1) All factors except PAHs, hexane and propylene from AP-42, Table 3.4-1. Acrolein, benzene and formaldehyde reflect oxidation catalyst. Individual PAHs, hexane and propylene are CATEF mean results as AP-42 does not include factors for these compounds.

(2) Based on maximum hourly turbine fuel use of 2094 MMBtu/hr and fuel HHV of 1012 Btu/scf. 2.07 MMscf/hr

(3) Based on total annual fuel use of 34,900,000 MMBtu/yr and fuel HHV of 1012 Btu/scf 34,486.2 MMscf/yr

(4) Based on 10 ppm ammonia slip from SCR system.

(5) Emission factors for individual PAHs weighted by cancer risk relative to B(a)P and summed to obtain overall B(a)P equivalent emission rate for HRA.

| | Mean EF | PEF Equiv. | PEF-Weighted EF |
|---|---|---|---|
| PAHs (as B(a)P) | | | |
| Benzo(a)anthracene | 2.26E-05 | 0.1 | 2.26E-06 |
| Benzo(a)pyrene | 1.39E-05 | 1 | 1.39E-05 |
| Benzo(b)fluoranthrene | 1.13E-05 | 0.1 | 1.13E-06 |
| Benzo(k)fluoranthrene | 1.10E-05 | 0.1 | 1.10E-06 |
| Chrysene | 2.52E-05 | 0.01 | 2.52E-07 |
| Dibenz(a,h)anthracene | 2.35E-05 | 1.05 | 2.47E-05 |
| Indeno(1,2,3-cd)pyrene | 2.35E-05 | 0.1 | 2.35E-06 |

**Table A-7**
**Gateway Generating Station**
**Calculation of Noncriteria Pollutant Emissions from Dewpoint Heater**

| Compound | Emission Factor, lb/MMscf (1) | Hourly Emissions, lb/hr (2) | Total Annual Emissions (3) lb/yr | tpy |
|---|---|---|---|---|
| Propylene | 7.30E-01 | 4.69E-03 | 41.0 | 2.05E-02 |
| Hazardous Air Pollutants | | | | |
| Acetaldehyde | 4.30E-03 | 2.76E-05 | 0.2 | 1.21E-04 |
| Acrolein | 2.70E-03 | 1.73E-05 | 0.2 | 7.59E-05 |
| Benzene | 8.00E-03 | 5.13E-05 | 0.4 | 2.25E-04 |
| 1,3-Butadiene | n/a | -- | -- | -- |
| Ethylbenzene | 9.50E-03 | 6.10E-05 | 0.5 | 2.67E-04 |
| Formaldehyde | 1.70E-02 | 1.09E-04 | 1.0 | 4.78E-04 |
| Hexane | 6.30E-03 | 4.04E-05 | 0.4 | 1.77E-04 |
| Naphthalene | 3.00E-04 | 1.93E-06 | 1.7E-02 | 8.43E-06 |
| PAHs (excluding naphthalene) | 1.00E-04 | 6.42E-07 | 5.6E-03 | 2.81E-06 |
| Propylene oxide | n/a | -- | -- | -- |
| Toluene | 3.66E-02 | 2.35E-04 | 2.1 | 1.03E-03 |
| Xylene | 2.72E-02 | 1.75E-04 | 1.5 | 7.65E-04 |
| Total HAPs | | | 6.3 | 3.15E-03 |

Notes:
(1) All factors from Ventura County APCD, "AB2588 Combustion Emission Factors," Natural Gas Fired External Combustion Equipment <10 MMBtu/hr. Available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf
(2) Based on maximum hourly heat input of 6418 scf/hr
(3) Based on total annual fuel use of 56.2 MMscf/yr

# Appendix B

## Modeling Parameters

**Table B-1**
**Gateway Generating Station**
**Building Dimensions Used for Modeling**

| Structure | Dimensions (meters) | | |
|---|---|---|---|
| | Height | Length (y) | Width (x) |
| Onsite Structures | | | |
| Combustion Turbines (each) | 17.4 | 10.0 | 79.0 |
| HRSGs (each) | 28.0 | 10.0 | 24.0 |
| Air-Cooled Condenser | 39.0 | 86.0 | 76.0 |
| Wet Surface Air Cooler | 5.8 | 4.0 | 17.0 |
| Dewpoint Heater | 1.8 | 8.0 | 1.0 |
| Firepump Engine Encl. | 3.3 | 21.0 | 12.0 |
| Tank 88 | 5.2 | 15.0 | |
| Tank 89 | 5.2 | 10.0 | |
| Tank 144 | 6.4 | 9.0 | |
| Tank 149 | 5.2 | 7.0 | |
| Offsite Structures | | | |
| Units 6&7 | 44.7 | 35.0 | 94.0 |
| Steam Turbine Bldg | 20.6 | 44.0 | 113.0 |
| Units 1-3 | 42.1 | 46.0 | 60.0 |
| Units 4&5 | 20.6 | 26.0 | 87.0 |
| Tanks 1-5 | 22.0 | 43.0 | |
| Tanks 6-8 | 29.3 | 98.0 | |

**Table B-2**
**Gateway Generating Station**
**Emissions and Stack Parameters for Screening Modeling**

| Turbine Case | | Ambient Temp | Load | Stack Diam (m) | Stack Ht (m) | Exhaust Temp (deg K) | Exhaust Velocity (m/s) | NOx, g/s per turbine | SO2, g/s per turbine | CO, g/s per turbine | PM10, g/s per turbine |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Number | Condition | | | | | | | | | | |
| 1 | Cold Base | 30.0 | 100% | 5.11 | 59.436 | 355.222 | 21.369 | 1.688 | 6.578E-01 | 2.056 | 1.386 |
| 2 | Cold Low | 30.0 | 50% | 5.11 | 59.436 | 355.222 | 13.979 | 1.104 | 4.303E-01 | 1.345 | 1.386 |
| 3 | Avg. Base | 60.0 | 100% | 5.11 | 59.436 | 355.222 | 21.567 | 1.688 | 6.578E-01 | 2.056 | 1.386 |
| 4 | Avg. Low | 60.0 | 50% | 5.11 | 59.436 | 355.222 | 14.844 | 1.162 | 4.527E-01 | 1.415 | 1.386 |
| 5 | Avg. Peak | 60.0 | 100% | 5.11 | 59.436 | 355.222 | 19.923 | 1.913 | 7.455E-01 | 2.330 | 1.512 |
| 6 | Hot Base | 100.0 | 100% | 5.11 | 59.436 | 355.222 | 22.120 | 1.688 | 6.578E-01 | 2.056 | 1.386 |
| 7 | Hot Low | 100.0 | 50% | 5.11 | 59.436 | 355.222 | 13.334 | 1.018 | 3.965E-01 | 1.239 | 1.386 |
| 8 | Hot Peak | 100.0 | 100% | 5.11 | 59.436 | 355.222 | 20.429 | 1.913 | 7.455E-01 | 2.330 | 1.512 |

# Exhibit No. 324

Pacific Gas & Electric Company – BAAQMD – Second Novation to May 1, 2009 Compliance Agreement

## Pacific Gas and Electric Co.-BAAQMD
## Second Novation To May 1, 2009, Compliance Agreement

This Second Novation To May 1, 2009, Compliance Agreement ("Second Novation Agreement") is hereby entered into this 31st Day of August, 2009, by and between PACIFIC GAS & ELECTRIC CO. ("PG&E") and the BAY AREA AIR QUALITY MANAGEMENT DISTRICT ("District"), hereinafter collectively referred to as the "Parties."

### RECITALS

WHEREAS, the Parties have previously entered into a Compliance Agreement, dated May 1, 2009 (a copy of which is attached hereto for reference as Attachment A), for the purpose of allowing EPA Region 9 to review the status of PG&E's compliance with Federal PSD Requirements applicable to the Gateway Generating Station (the "Facility"). The Compliance Agreement provides for PG&E to continue operating the Facility after the expiration of the startup period in accordance with the terms and conditions of its Authority to Construct, but without having received a Permit to Operate, for one additional month, until June 1, 2009.

WHEREAS, the District did not issue a Permit to Operate during this time period because it took the position that, under District Regulation 2-1-304, it is not authorized to issue a Permit to Operate to a facility that would not or does not comply with Federal PSD Requirements. The District took the position that it would not be appropriate to issue a Permit to Operate at that time because of the outstanding question regarding the Facility's compliance with the Federal PSD Requirements, and that it wanted to provide EPA Region 9 with the time necessary to review the issue and make a determination before taking any action on the Permit to Operate.

WHEREAS, during the term of the Compliance Agreement as initially entered into between the Parties, EPA Region 9 undertook a compliance review and adopted an interpretation that although the District issued several extensions to its Authority to Construct in the past several years and intended that the extensions would be effective to extend the Facility's Federal PSD Permit pursuant to the Delegation Agreement between the two agencies, in hindsight, the Facility's Federal PSD Permit expired and was not validly extended when the District issued extensions of the Authority to Construct. PG&E disagreed with EPA Region 9's interpretation, and contended that the Federal PSD Permit for the Facility was duly extended and did not expire. Notwithstanding their disagreement on the issue of the expiration of the Federal PSD Permit for the Gateway Generating Station, PG&E and EPA Region 9 entered into and are continuing settlement discussions in the hopes that they can mutually resolve any claims by EPA Region 9 of non-compliance with any applicable Federal PSD requirements.

WHEREAS, the District defers to EPA Region 9's interpretation of Federal PSD issues under the Delegation Agreement between the two agencies. In light of EPA Region 9's recent interpretation, and with unresolved allegations by EPA of non-compliance with Federal PSD requirements, the District has taken the position that it would not be appropriate to issue a Permit to Operate for the Gateway Generating Station at this time pursuant to District Regulation 2-1-304.

WHERAS, while these settlement discussions have been taking place, EPA Region 9 has not taken any action in connection with any claims of non-compliance with Federal PSD requirement to enjoin PG&E from operation of the Facility, and has not given any indication that it intends to take such action;

WHEREAS, the District is mindful that EPA Region 9 is continuing to allow the Facility to operate under the conditions of the Federal PSD Permit that was initially issued for the Facility pending resolution of the allegations of PSD non-compliance, and that EPA Region 9 is apparently hopeful that its claims can ultimately be resolved in a manner that will cure any alleged non-compliance. Under the circumstances, it would not be in the interests of justice for the District to require the Facility to cease operation based on claims of non-compliance with federal requirements for which EPA Region 9, the federal agency charged with administering and enforcing those requirements, does not believe warrant a cessation in operation pending resolution of the outstanding enforcement issues, so long as PG&E continues to comply with the applicable terms and conditions set forth in the Authority to Construct;

WHEREAS, in order to preserve the *status quo* pending resolution of settlement discussions between PG&E and EPA Region 9, the Parties entered into a Novation Agreement dated June 1, 2009 ("First Novation Agreement") (a copy of which is attached hereto for reference as Attachment B) extending the term of the Compliance Agreement as initially entered into for three months, through September 1, 2009.

WHEREAS, settlement negotiations have been proceeding, and EPA Region 9 has issued a Finding and Notice of Violation to PG&E regarding the alleged PSD non-compliance at the Facility, which is a necessary prerequisite to any settlement of such allegations, but the negotiations have not yet been completed;

WHEREAS, the time period provided for in the Compliance Agreement, as modified by the First Novation Agreement, is expiring on September 1, 2009, but additional time is needed to allow EPA Region 9 and PG&E to continue their settlement negotiations;

WHEREAS, the Parties now wish to extend the time period provided for in the Compliance Agreement, as modified by the First Novation Agreement, for an additional 90 days based on the time it will likely take for the settlement negotiations between EPA Region 9 and PG&E to come to a complete resolution;

WHEREAS, the Parties also wish to add to the Compliance Agreement the future use and operation of the diesel emergency firepump engine that has been installed at the Facility, which was not included in the Authority to Construct issued for the facility. Although the diesel emergency firepump engine was not included in the Authority to Construct, the District has reviewed information regarding the diesel emergency firepump engine and has determined that it can be operated in conformance with applicable regulatory requirements if the District were to issue a permit for it;

WHEREAS, the Parties intend and wish to agree that the District will allow the future use of the diesel emergency firepump engine consistent with this agreement on the condition that PG&E will operate it pursuant to and only in compliance with all of the conditions attached

hereto as Attachment C ("Draft Emergency Firepump Engine Permit Conditions"). The Parties also intend and wish to agree that this Agreement covers only future use of the diesel emergency firepump engine under this agreement, and not the installation of or any past usage of the diesel emergency firepump engine before the date of this Second Novation Agreement.

## AGREEMENT

NOW, THEREFORE, based on the foregoing recitals, and in consideration of the mutual promises and covenants contained in this Second Novation Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. The Parties agree that the May 1, 2009, Compliance Agreement entered into between them, as modified by the First Novation Agreement, shall be and hereby is further modified, pursuant to Paragraph 13 of the Compliance Agreement and Paragraph 10 of the First Novation Agreement, by replacing the September 1, 2009, termination date effective pursuant to Paragraph 1 of the First Novation Agreement with a new termination date of December 1, 2009.

2. The Parties further agree that the that the May 1, 2009, Compliance Agreement, as modified by the First Novation Agreement and this Second Novation Agreement, shall authorize the operation and use of the diesel emergency firepump engine as part of the Gateway Generating Station between the date of this Second Novation Agreement and the termination date of the agreement. PG&E expressly agrees that it will operate the diesel emergency firepump engine pursuant to and only in compliance with all of the conditions attached hereto as Attachment C ("Draft Emergency Firepump Engine Permit Conditions"). The authorization for use of the diesel emergency firepump engine pursuant to this Paragraph 2 shall not apply to any operation in violation of the conditions in Attachment C, nor to the installation of or any past usage of the diesel emergency firepump engine before the date of this Second Novation Agreement, for which the District reserves the right to take any and all available enforcement action, to the extent any exists.

3. The Parties expressly agree and intend that this Second Novation Agreement amends the May 1, 2009, Compliance Agreement, as modified by the First Novation Agreement, only as expressly set forth herein. The Parties expressly agree and intend that all provisions of the May 1, 2009, Compliance Agreement, as modified by the First Novation Agreement, remain in force and effect as provided in that Agreement except as expressly set forth herein.

4. The terms of this Second Novation Agreement shall inure to the benefit of and be binding upon the Parties and their respective predecessors, successors, subsidiaries, partners, limited partners, agents, principals and assigns.

5. If any provision of this Second Novation Agreement or the application of this Second Novation Agreement to either PG&E or the District is held by any judicial authority to be invalid, the application of such provision to the other Party and the remainder of this Second Novation Agreement shall remain in force and shall not be affected thereby, unless such holding materially changes the terms of this Second Novation Agreement.

6. Each of the undersigned represents and warrants that he or she has full and complete lawful authority to grant, bargain, convey and undertake the rights and duties contained in this Second Novation Agreement, and that he or she has full and complete lawful authority to bind any respective principals, successors, subsidiaries, partners, limited partners, agents and assigns to this Second Novation Agreement. Each of the undersigned understands and agrees that this representation and warranty is a material term of this Second Novation Agreement, without which it would not have been executed.

7. PG&E and the District hereby affirm and acknowledge that they have read this Second Novation Agreement, that they know and understand its terms, and that they have signed it voluntarily and on the advice of counsel of their own choosing. The Parties have had the opportunity to consult with their attorneys and any other consultant each deemed appropriate prior to executing this Second Novation Agreement.

8. The mutual obligations and undertakings of PG&E, on the one hand, and the District, on the other hand, expressly set forth in this Second Novation Agreement are the sole and only consideration for this Second Novation Agreement, and supersede and replace all prior negotiations and proposed agreements between PG&E and the District, written or oral, on the specific matters addressed in this Second Novation Agreement. PG&E and the District each acknowledges that no other party, nor the agents nor attorneys of any other party, has made any promise, representation or warranty whatsoever (express or implied), not contained herein, to induce the execution of this Second Novation Agreement. This Second Novation Agreement constitutes the full, complete and final statement of PG&E and the District on the matters addressed by this Second Novation Agreement.

9. PG&E and the District have jointly prepared this Second Novation Agreement. This Second Novation Agreement shall be deemed to have been jointly drafted by the Parties for the purpose of applying any rule of construction to the effect that ambiguities are to be construed against the party drafting the agreement.

10. This Second Novation Agreement may be executed in one or more counterparts, each of which shall have the same force and effect as an original, but all of which together shall constitute one and the same instrument.

11. This Second Novation Agreement may be amended, supplemented or extended only by a written instrument signed by both PG&E and the District or their successors-in-interest. However, such execution may be in counterparts and, when so executed, shall be deemed to constitute one and the same document.

12. Any material breach of this Second Novation Agreement by either Party shall make the Agreement subject to termination upon notice by the non-breaching Party.

13. The waiver of any provision or term of this Second Novation Agreement shall not be deemed as a waiver of any other provision or term of this Second Novation Agreement. The mere passage of time, or failure to act upon a breach, shall not be deemed as a waiver of any provision or term of this Second Novation Agreement.

14. This Second Novation Agreement shall be interpreted and enforced in accordance with the laws of the State of California, without regard to California's choice-of-law rules.

* * * * *

IN WITNESS WHEREOF, the Parties acknowledge and accept this Second Novation Agreement.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

By: _____
Jack P. Broadbent
Air Pollution Control Officer/
Executive Officer

Approved as to form:

_____
Brian C. Bunger, Esq.
District Counsel

PACIFIC GAS AND ELECTRIC CO.

By: _____
~~Steve G. Royall~~ Ronald A. Gawer
Plant Manager

Approved as to form:

_____
David T. Kraska, Esq.
Director and Counsel

**ATTACHMENT A**

# Pacific Gas and Electric Co.-BAAQMD
# Compliance Agreement

This Compliance Agreement ("Agreement") is entered into this 1st day of May, 2009, between Pacific Gas and Electric Co. ("PG&E") and the Bay Area Air Quality Management District ("BAAQMD" or "District"), hereinafter collectively referred to as the "Parties."

## RECITALS

WHEREAS, the District is the regional agency with primary responsibility for the enforcement of California air pollution control laws regarding stationary sources in the San Francisco Bay Area Air Basin;

WHEREAS, PG&E owns and operates an electric power generating facility known as the Gateway Generating Station within the San Francisco Bay Area Air Basin, located at 3225 Wilbur Avenue in Antioch, CA, ("the facility"), which is subject to District jurisdiction;

WHEREAS, the District has issued an Authority to Construct authorizing the construction and initial operation of two combustion gas turbines at the facility (along with heat recovery steam generators and other related equipment), subject to various conditions designed to ensure compliance with applicable air pollution control regulations;

WHEREAS, PG&E constructed and commenced operation of the facility pursuant to the Authority to Construct issued by the District;

WHEREAS, District regulations authorize operation of a facility under an Authority to Construct for an initial startup period of a maximum of 180 days, after which the facility must obtain a Permit to Operate in order to continue operating;

WHEREAS, PG&E has been operating the facility under the startup authorization under the Authority to Construct, and the 180-day startup period expires on May 1, 2009;

WHEREAS, PG&E has applied to the District for a Permit to Operate to authorize continued operation beyond the end of the startup period under the Authority to Construct;

WHEREAS, pursuant to District Regulation 2-1-304, the District must deny a Permit to Operate if it finds that the subject of the application will not or does not comply with applicable emission limitations in permit conditions or District, California or federal laws or regulations;

WHEREAS, PG&E has provided to the District information that PG&E contends supports its view that the facility is in compliance with all applicable emission limitations and requirements set forth in District, California, and federal laws, regulations, and permit conditions;

WHEREAS, the District has reviewed information from PG&E regarding compliance with the conditions of the Authority to Construct and has not found any element of the facility currently operating out of compliance with those conditions or with any applicable emission limitations in District or California laws or regulations, and is therefore not aware of any reason that the permit must be denied under District Regulation 2-1-304 because of any non-compliance with state-law requirements;

WHEREAS, with regard to federal requirements, Region IX of the United States Environmental Protection Agency (EPA) is reviewing the facility's compliance with the applicable requirements of the federal Prevention of Significant Deterioration program of the Federal Clean Air Act, 42 U.S.C. § 7401 *et seq.*;

WHEREAS, EPA Region IX has informed the District that it expects to complete its compliance review within a few weeks, but not before the end of the startup period;

WHEREAS, because of the pending review by EPA Region IX regarding compliance with Federal PSD requirements, the District cannot make a determination before the end of the startup period as to whether the facility will not or does not comply with an emission limitation under federal law as required to issue a Permit to Operate for the facility under District Regulation 2-1-304;

WHEREAS, the District expects EPA Region IX to complete its review of Federal PSD requirements sufficient to allow the District to make a permitting determination under District Regulation 2-1-304 by June 1, 2009;

WHEREAS, the District believes that it would be inappropriate under these circumstances to require PG&E to cease operation of the facility as a result of the expiration of the startup period under the Authority to Construct pending completion of the compliance review by EPA Region IX and subsequent permitting determination by the District, provided that PG&E operates in compliance with the conditions of the Authority to Construct; and

WHEREAS, the District is vested with:

(i) enforcement authority for the air pollution control program in accordance with California Health & Safety Code Sections 40001, 40701, 40752, 42400-42421, and 42451-42454; and

(ii) discretion over the application of this enforcement authority given the facts and circumstances of each enforcement matter,

and has determined that, in view of the circumstances recited above, it will not take civil or criminal penalty action against PG&E for continued operation of the facility until after the date of termination of this Agreement as established under Paragraphs 3 and 13 of this Agreement, if at all, or until PG&E obtains a Permit to Operate if that event occurs before June 1, 2009, as long as PG&E strictly adheres to the conditions of the Authority to Construct and to the conditions set forth in this Agreement.

## AGREEMENT

NOW, THEREFORE, based on the foregoing recitals, and in consideration of the mutual promises and covenants contained in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. PG&E agrees that it shall not operate the facility pursuant to this Agreement except in strict compliance with all applicable conditions of the Authority to Construct. PG&E further agrees that it shall not operate the facility pursuant to this Agreement after the date of termination of this Agreement as established in Paragraph 3 of this Agreement below.

2. The District agrees that it shall not issue a Notice of Violation, seek civil or criminal penalties, seek injunctive relief, or otherwise take enforcement action against PG&E (i) for operation of the facility after the end of the startup period as authorized under the Authority to Construct or (ii) for operation of the facility without having received a Permit to Operate, except as expressly provided for in this Agreement. The District reserves all rights to take enforcement action as provided for by law should PG&E operate the facility in violation of the conditions in the Authority to Construct, in violation of the terms of this Agreement, or after the date of termination of this Agreement as established in Paragraph 3 of this Agreement below.

3. a. This Agreement shall be effective as of May 1, 2009; and it shall terminate on the first to occur of: (i) June 1, 2009, or (ii) the date on which PG&E receives a Permit to Operate for the facility. PG&E shall not operate the facility pursuant to this Agreement after the date of termination as established in this Paragraph 3.

b. Notwithstanding subparagraph 3.a., if PG&E has not received a Permit to Operate for the facility by May 25, 2009 and does not expect to receive the Permit to Operate on or before June 1, 2009, between May 25 and June 1 PG&E may notify the District that EPA is continuing its compliance review. Such notice shall extend the termination date of this Agreement to the earlier of June 15, 2009, or the date on which PG&E receives a Permit to Operate for the facility. Any subsequent extension of this Agreement shall be made in accordance with Paragraph 13 of this Agreement.

4. This Agreement is binding upon PG&E and the District only with respect to the matters specifically addressed herein and does not otherwise bind PG&E and/or the District.

5. The terms of this Agreement shall inure to the benefit of and be binding upon the Parties and their respective predecessors, successors, subsidiaries, partners, limited partners, agents, principals, and assigns.

6. If any provision of this Agreement or the application of this Agreement to either PG&E or the District is held by any judicial authority to be invalid, the application of such provision to the other Party and the remainder of this Agreement shall remain in force and shall not be affected thereby, unless such holding materially changes the terms of this Agreement.

7. Each of the undersigned represents and warrants that he or she has read and understands and has full and complete lawful authority to grant, bargain, convey, and undertake the rights and duties contained in this Agreement, and that he or she has full and complete lawful authority to bind any respective principals, successors, subsidiaries, partners, limited partners, agents and assigns to this Agreement. Each of the undersigned understands and agrees that this representation and warranty is a material term of this Agreement, without which it would not have been executed.

8. PG&E and the District each hereby affirms and acknowledges that it has read this Agreement, that it knows and understands the terms of this Agreement, and that it has signed this Agreement voluntarily. The Parties have had the opportunity to consult with their respective attorneys and any other consultant each deemed appropriate prior to executing this Agreement.

9. This Agreement shall be governed by and construed in accordance with the laws of the State of California.

10. The mutual obligations and undertakings of PG&E on the one hand, and the District on the other hand, expressly set forth in this Agreement are the sole and only consideration of this Agreement and supersede and replace all prior negotiations and proposed agreements between PG&E and the District, written or oral, on the specific matters addressed in this Agreement. PG&E and the District each acknowledges that no other party, nor the agents nor attorneys of any other party, has made any promise, representation or warranty whatsoever (express or implied), not contained herein, to induce the execution of this Agreement. This Agreement constitutes the full, complete and final statement of PG&E and the District on the matters addressed by this Agreement.

11. This Agreement may be executed in one or more counterparts, each of which shall have the same force and effect as an original, but all of which together shall constitute one and the same instrument.

12. PG&E and the District have jointly prepared this Agreement. This Agreement shall be deemed to have been jointly drafted by the Parties for the purpose of applying any rule of construction to the effect that ambiguities are to be construed against the party drafting the agreement.

13. This Agreement may be amended and supplemented only by a written instrument signed by both PG&E and the District or their successors-in-interest. However, such execution may be in counterparts and, when so executed, shall be deemed to constitute one and the same document.

14. Any material breach of this Agreement by either Party shall make the Agreement subject to termination upon notice by the non-breaching Party.

15. The waiver of any provision or term of this Agreement shall not be deemed as a waiver of any other provision or term of this Agreement. The mere passage of time, or failure to act upon a breach, shall not be deemed as a waiver of any provision or term of this Agreement.

IN WITNESS WHEREOF, the Parties acknowledge, agree to and accept this Agreement.

BAY AREA AIR QUALITY
MANAGEMENT DISTRICT

By: _____
For Jack P. Broadbent
Air Pollution Control Officer/
Chief Executive Officer

Date: 5/4/09

Approved as to form:

_____
FOR Brian C. Bunger, Esq.
District Counsel

Date: 5/4/09

PACIFIC GAS AND ELECTRIC CO.

By: _____
Steve G. Royall
Plant Manager

Date: 5/1/09

Approved as to form:

_____
David T. Kraska, Esq.
Director and Counsel

Date: 5/1/09

**ATTACHMENT B**

**Pacific Gas and Electric Co.-BAAQMD**
**Novation To May 1, 2009, Compliance Agreement**

This Novation To May 1, 2009, Compliance Agreement ("Novation Agreement") is hereby entered into this 1st Day of June, 2009, by and between PACIFIC GAS & ELECTRIC CO. ("PG&E") and the BAY AREA AIR QUALITY MANAGEMENT DISTRICT ("District"), hereinafter collectively referred to as the "Parties."

**RECITALS**

WHEREAS, the Parties have previously entered into a Compliance Agreement, dated May 1, 2009 (a copy of which is attached hereto for reference), for the purpose of allowing EPA Region 9 to review the status of PG&E's compliance with Federal PSD Requirements applicable to the Gateway Generating Station. The Compliance Agreement provides for PG&E to continue operating the Gateway facility after the expiration of the startup period in accordance with the terms and conditions of its Authority to Construct, but without having received a Permit to Operate, for one additional month, until June 1, 2009.

WHEREAS, EPA Region 9 has undertaken its compliance review and has adopted an interpretation that although the District issued several extensions to its Authority to Construct in the past several years and intended that the extensions would be effective to extend the facility's Federal PSD Permit pursuant to the Delegation Agreement between the two agencies, in hindsight, the facility's Federal PSD Permit expired and was not validly extended when the District issued extensions of the Authority to Construct;

WHEREAS, PG&E disagrees with EPA Region 9's interpretation, and contends that the Federal PSD Permit for the facility was duly extended and did not expire;

WHEREAS, notwithstanding their disagreement on the issue of the expiration of the Federal PSD Permit for the Gateway Generating Station, PG&E and EPA Region 9 have entered into and are continuing settlement discussions in the hopes that they can mutually resolve any claims by EPA Region 9 of non-compliance with any applicable Federal PSD requirements. PG&E and EPA Region 9 anticipate that these discussions will require approximately 90 days to complete.

WHERAS, while these settlement discussions have been taking place, EPA Region 9 has not taken any action in connection with any claims of non-compliance with Federal PSD requirement to enjoin PG&E from operation of the facility, and has not given any indication that it intends to take such action;

WHEREAS, the District defers to EPA Region 9's interpretation of Federal PSD issues under the Delegation Agreement between the two agencies. In light of EPA Region 9's recent interpretation, and with unresolved allegations by EPA of non-compliance with Federal PSD requirements, the District does not believe that it can issue a Permit to Operate for the Gateway Generating Station at this time pursuant to District Regulation 2-1-304.

WHEREAS, the District is also mindful that EPA Region 9 is continuing to allow the facility to operate under the conditions of the Federal PSD Permit that was initially issued for the facility pending resolution of these allegations, and is apparently hopeful that its claims can ultimately be resolved in a manner that will cure any alleged non-compliance. Under the circumstances, it would not be in the interests of justice for the District to require the facility to cease operation based on claims of non-compliance with federal requirements for which EPA Region 9, the federal agency charged with administering and enforcing those requirements, does not believe warrant a cessation in operation pending resolution of the outstanding enforcement issues, so long as PG&E continues to comply with the applicable terms and conditions set forth in the Authority to Construct;

WHEREAS, in order to preserve the *status quo* pending resolution of settlement discussions between PG&E and EPA Region 9, the Parties now wish to extend the time period provided for in the Compliance Agreement for an additional 90 days based on the time it will likely take to reach such a resolution;

## AGREEMENT

NOW, THEREFORE, based on the foregoing recitals, and in consideration of the mutual promises and covenants contained in this Novation Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. The Parties agree that the May 1, 2009, Compliance Agreement entered into between them shall be and hereby is amended, pursuant to Paragraph 13 of the Compliance Agreement, by replacing the June 1, 2009, termination date set forth in Paragraph 3.a.(i) of the Compliance Agreement with a new termination date of September 1, 2009.

2. The Parties expressly agree and intend that this Novation Agreement amends the May 1, 2009, Compliance Agreement only as expressly set forth herein. The Parties expressly agree and intend that all provisions of the May 1, 2009, Compliance Agreement remain in force and effect as provided in that Agreement except as expressly set forth herein.

3. The terms of this Novation Agreement shall inure to the benefit of and be binding upon the Parties and their respective predecessors, successors, subsidiaries, partners, limited partners, agents, principals and assigns.

4. If any provision of this Novation Agreement or the application of this Novation Agreement to either PG&E or the District is held by any judicial authority to be invalid, the application of such provision to the other Party and the remainder of this Novation Agreement shall remain in force and shall not be affected thereby, unless such holding materially changes the terms of this Novation Agreement.

5. Each of the undersigned represents and warrants that he or she has full and complete lawful authority to grant, bargain, convey and undertake the rights and duties contained in this Novation Agreement, and that he or she has full and complete lawful authority to bind any respective principals, successors, subsidiaries, partners, limited partners, agents and assigns to

this Novation Agreement. Each of the undersigned understands and agrees that this representation and warranty is a material term of this Novation Agreement, without which it would not have been executed.

6. PG&E and the District hereby affirm and acknowledge that they have read this Novation Agreement, that they know and understand its terms, and that they have signed it voluntarily and on the advice of counsel of their own choosing. The Parties have had the opportunity to consult with their attorneys and any other consultant each deemed appropriate prior to executing this Novation Agreement.

7. The mutual obligations and undertakings of PG&E, on the one hand, and the District, on the other hand, expressly set forth in this Novation Agreement are the sole and only consideration for this Novation Agreement, and supersede and replace all prior negotiations and proposed agreements between PG&E and the District, written or oral, on the specific matters addressed in this Novation Agreement. PG&E and the District each acknowledges that no other party, nor the agents nor attorneys of any other party, has made any promise, representation or warranty whatsoever (express or implied), not contained herein, to induce the execution of this Novation Agreement. This Novation Agreement constitutes the full, complete and final statement of PG&E and the District on the matters addressed by this Novation Agreement.

8. PG&E and the District have jointly prepared this Novation Agreement. This Novation Agreement shall be deemed to have been jointly drafted by the Parties for the purpose of applying any rule of construction to the effect that ambiguities are to be construed against the party drafting the agreement.

9. This Novation Agreement may be executed in one or more counterparts, each of which shall have the same force and effect as an original, but all of which together shall constitute one and the same instrument.

10. This Novation Agreement may be amended, supplemented or extended only by a written instrument signed by both PG&E and the District or their successors-in-interest. However, such execution may be in counterparts and, when so executed, shall be deemed to constitute one and the same document.

11. Any material breach of this Novation Agreement by either Party shall make the Agreement subject to termination upon notice by the non-breaching Party.

12. The waiver of any provision or term of this Novation Agreement shall not be deemed as a waiver of any other provision or term of this Novation Agreement. The mere passage of time, or failure to act upon a breach, shall not be deemed as a waiver of any provision or term of this Novation Agreement.

13. This Novation Agreement shall be interpreted and enforced in accordance with the laws of the State of California, without regard to California's choice-of-law rules.

IN WITNESS WHEREOF, the Parties acknowledge and accept this Novation Agreement.

BAY AREA AIR QUALITY
MANAGEMENT DISTRICT

By: _____
for Jack P. Broadbent
Air Pollution Control Officer/
Executive Officer

PACIFIC GAS AND ELECTRIC CO.

By: _____
Steve G. Royall
Plant Manager

Approved as to form:

_____
Brian C. Bunger, Esq.
District Counsel

Approved as to form:

_____
David T. Kraska, Esq.
Director and Counsel

**ATTACHMENT C**

COND# TBD ----------

1. The owner/operator shall not exceed 50 hours per year per engine for reliability-related testing.
[Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3) or (e)(2)(B)(3)]

2. The owner/operator shall operate each emergency standby engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, State or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating while mitigating emergency conditions or while emission testing to show compliance with District, State or Federal emission limits is not limited.
[Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3) or (e)(2)(B)(3)]

3. The owner/operator shall operate each emergency standby engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained.
[Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection(e)(4)(G)(1)]

4. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 36 months from the date of entry (60 months if the facility has been issued a Title V Major Facility Review Permit or a Synthetic Minor Operating Permit). Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
   a. Hours of operation for reliability-related activities (maintenance and testing).
   b. Hours of operation for emission testing to show compliance with emission limits.
   c. Hours of operation (emergency).
   d. For each emergency, the nature of the emergency condition.
   e. Fuel usage for each engine(s).

[Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), (or, Regulation 2-6-501)]

5. At School and Near-School Operation:

If the emergency standby engine is located on school grounds or within 500 feet of any school grounds, the following requirements shall apply:

The owner/operator shall not operate each stationary emergency standby diesel-fueled engine for non-emergency use, including maintenance and testing, during the following periods:

a. Whenever there is a school sponsored activity (if the engine is located on school grounds)

b. Between 7:30 a.m. and 3:30 p.m. on days when school is in session. "School" or "School Grounds" means any public or private school used for the purposes of the education of more than 12 children in kindergarten or any of grades 1 to 12, inclusive, but does not include any private school in which education is primarily conducted in a private home(s). "School" or "School Grounds" includes any building or structure, playground, athletic field, or other areas of school property but does not include unimproved school property.

[Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(1)] or (e)(2)(B)(2)]

# Exhibit No. 323

PG&E Errata to the Brief on Jurisdictional Issues and Motion for Summary Disposition (Dismissal) submitted to US EPA Environmental Appeals Board, dated and filed July 23, 2009.

BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

| | |
|---|---|
| In the Matter of:<br>Gateway Generating Station | PSD Appeal No. 09-02 |

**PACIFIC GAS AND ELECTRIC COMPANY'S**

**ERRATA TO THE BRIEF ON JURISDICTIONAL ISSUES AND MOTION FOR SUMMARY DISPOSITION (DISMISSAL)**

**AND TO THE DECLARATION OF GARY S. RUBENSTEIN**

Intervenor PG&E filed its Brief on Jurisdictional Issues and Motion for Summary Disposition (Dismissal) on July 2, 2009, which was accompanied by a declaration of Gary S. Rubenstein.

Footnote 3 on page 3 of the Brief states: "The EPA-BAAQMD PSD delegation agreement in effect at the time that BAAQMD issued the facility's permit was the April 23, 1986 agreement, (R. Decl. at ¶ 3, Exh. A)." That footnote should instead state: "The EPA-BAAQMD PSD delegation agreement in effect at the time that BAAQMD issued the facility's permit was the October 28, 1997 agreement, (R. Decl. at ¶ 3, Exh. A)." This correction in no way alters PG&E's arguments.

Paragraph 3 of Mr. Rubenstein's declaration should also be corrected to refer to the October 28, 1997 delegation agreement rather than the 1986 agreement.

A corrected page of the brief and a corrected page of Mr. Rubenstein's declarations are attached hereto.

DATED July 23, 2009.

Respectfully submitted,

PILLSBURY WINTHROP SHAW PITTMAN LLP

By _____
Attorneys for Pacific Gas and Electric Company

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## CERTIFICATE OF SERVICE

I the undersigned, hereby certify that on the 23 day of July, 2009, service of a true and complete copy of **Pacific Gas & Electric Company's Erratum to the Declaration of Gary S. Rubenstein** was made upon the following parties:

Jack Broadbent
Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
phone: (415) 749-5000
fax: (415) 928-8560

Rob Simpson
27126 Grandview Avenue
Hayward, CA 94542

Nancy Marvel, Esq., Regional Counsel
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, Ca 94105
phone: (415) 947-8705

PROPOSED INTERVENOR
CAlifornians for Renewable Energy, Inc.
Robert Sarvey
Lynne Brown
24 Harbor Road
San Francisco, CA 94124
Phone: (415) 285-4628

by depositing the same in the U.S. Mail.

I declare under penalty of perjury that the foregoing is true and correct.

Bertha I. Necochea

For these reasons, as set forth more fully below, PG&E respectfully requests that the EAB determine that it has no jurisdiction over the instant Appeal, and that the Petition be summarily dismissed.

## I. BACKGROUND

Pursuant to the Clean Air Act and EPA regulations, BAAQMD implements the federal PSD permit program in the San Francisco Bay Area. *See* Clean Air Act ("CAA") §§ 107(a), 110; 42 U.S.C. §§ 7407(a), 7410; 40 C.F.R. § 52.21(u). The District administers the PSD permit program through a contractual "delegation agreement" with EPA. *See, e.g.,* "U.S. EPA-Bay Area AQMD Agreement for Delegation of Authority for Prevention of Significant Deterioration of Air Quality Program (40 CFR 52.21)," dated April 23, 1986, (R. Decl., Exh. A.). In delegating to the District the authority to administer the PSD permit program, EPA determined that District Regulation 2, Rule 2 "generally meets the requirements of 52.21; therefore, *District Authorities to Construct (ATCs or permits) will be deemed to meet Federal PSD permit requirements. . . .*" *Id.*, emphasis added. Pursuant to the terms of this delegation agreement, the District issues a single permit that functions as both a District ATC and a PSD permit. *See also* District Regulations 2-2-101, 2-2-304, R. Decl., Exh. B.)

Pursuant to District regulations, on July 24, 2001 the District issued an ATC for the facility (R. Decl., ¶ 9, Exh. C, pp. 1, 23-36).[2] Consistent with the PSD delegation agreement, the ATC included the PSD permit.[3] *Id.* Construction of the

---

[2] The ATC was issued to Mirant Delta, LLC, which originally owned the facility, and at the time the ATC was issued referred to the facility as Contra Costa Unit 8. PG&E acquired the facility on November 30, 2006 and BAAQMD transferred the District permit (including the PSD permit) to PG&E on January 4, 2007. (R. Decl. at ¶¶ 1, 9.) In some documents, EPA refers to the facility as the "Delta Power Plant." After acquiring the facility, PG&E renamed the facility the Gateway Generating Station. For consistency, the project will be referred to as "Gateway" or "the facility" in this Brief.

[3] The EPA-BAAQMD PSD delegation agreement in effect at the time that BAAQMD issued the facility's permit was the October 28, 1997 agreement, (R. Decl. at ¶ 3, Exh. A). For various

CORRECTED (continued...)

3. The Bay Area Air Quality Management District ("BAAQMD" or the "District") administers the federal PSD permit program through a contractual "delegation agreement" with EPA. Attached hereto as Exhibit A is a true and correct copy of the "U.S. EPA-Bay Area AQMD Agreement for Delegation of Authority for Prevention of Significant Deterioration of Air Quality Program (40 CFR 52.21)," dated October 28, 1997, which was in effect when the District issued the Authority to Construct identified in paragraph 9 hereof, infra.

4. For various reasons related to changes in state and federal law, in 2004 EPA re-delegated limited authority to the District to administer the federal PSD permit program. Attached hereto as Exhibit D is a true and correct copy of the "U.S. EPA – Bay Area Air Quality Management District Agreement for Re-Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21," dated June 21, 2004. The facility is referred to in that document as the "Delta Power Plant."

5. In 2008, EPA again delegated authority over the federal PSD permit program to the District, expanding the scope of the previous delegation. Attached hereto as Exhibit E is a true and correct copy of the "U.S. EPA – Bay Area Air Quality Management District Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21," dated February 4, 2008.

6. The U.S. EPA-Bay Area AQMD Agreement and the District's own regulations contemplate that the District issues a single permit that functions as both a District Authority to Construct ("ATC") and a PSD permit. Attached hereto as Exhibit B is a true and correct copy of the current version of relevant District regulations, contained in its Regulation 2, Rule 2. With respect to the matters at issue in this proceeding, the relevant District regulations are the same today as they were at the time BAAQMD issued the PSD permit in 2001.

higher than 5,666 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

46. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the CCPP Unit 8, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. The CEC CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the $PM_{10}$ emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD)

47. The Fuel Gas Preheater (S-45) shall not be operated more than 16 hours in any day. (BACT)

# V Recommendation

The APCO has concluded that the proposed CCPP Unit 8 power plant, which is composed of the permitted sources listed below, complies with all applicable District rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

**S-41 Combustion Gas Turbine #1, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.**

**S-42 Heat Recovery Steam Generator #1, 395 MM Btu per hour, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.**

**S-43 Combustion Gas Turbine #2, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.**

**S-44 Heat Recovery Steam Generator #2, 395 MM Btu per hour, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.**

**S-45 Gas-Fired Fuel Preheater, 12 MM Btu per hour.**

**S-46 10-Cell Wet Cooling Tower, 125,000 gallons per minute**

Pursuant to District Regulation 2-3-404, this document shall be subject to the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407.

Written comments on this Preliminary Determination of Compliance should be directed to:

Ellen Garvey
Air Pollution Control Officer/Executive Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109

# EXHIBIT I

# Final
# Determination of Compliance

## Contra Costa Power Plant
## Unit 8 Project

Bay Area Air Quality Management District
Application 1000

February 2, 2001

Dick Wocasek, P.E.
Air Quality Engineer

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# I Introduction

This is the Final Determination of Compliance (FDOC) for the Unit 8 Project at the existing Contra Costa Power Plant (CCPP), a 530-MW, natural-gas fired, combined cycle merchant power plant proposed by Southern Energy California. The existing power plant is located about 1-mile northeast of the city of Antioch on Wilbur Avenue near State Route (SR) 4, SR 160 and the Antioch Bridge. The new unit will include two natural gas fired General Electric Frame 7FA combustion turbine generators (CTGs), one steam turbine generator and associated equipment, two supplementally fired heat recovery steam generators (HRSGs) and a wet cooling tower.

## A. Background

Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Final Determination of Compliance (FDOC) document for the CCPP Unit 8. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #1000. The FDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, this FDOC has fulfilled the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

## B. Project Description

### 1. Process Equipment

The applicant is proposing a combined-cycle combustion turbine power generation facility with a maximum electrical output of 530 MW. The CCPP Unit 8 will consist of the following new permitted equipment:

S-41 Combustion Gas Turbine #1, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-42 Heat Recovery Steam Generator #1, 395 MM Btu per hour, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-43 Combustion Gas Turbine #2, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-44 Heat Recovery Steam Generator #2, 395 MM Btu per hour, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-45 Gas-Fired Fuel Preheater, 12 MM Btu per hour.

S-46 10-Cell Wet Cooling Tower, 125,000 gallons per minute

As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 175 MW and the steam produced by both heat recovery steam generators (HRSGs) will feed to a single steam turbine generator with a nominal electrical output of 192 MW.

## 2. Equipment Operating Scenarios

*Turbines and Heat Recovery Steam Generators*

As a merchant power plant, market circumstances and demand will dictate the exact operation of the new gas turbine/HRSG power trains. However, the following general operating modes are projected to occur:

*Base Load:* Maximum continuous output with duct firing and power augmentation steam injection during high ambient temperature conditions

*Load Following:* Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

*Partial Shutdown:* Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during period of low overall demand such as late evening and early morning hours

*Full Shutdown:* May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

*HRSG Duct Burner Firing with Steam Injection Power Augmentation:*

Under peak demand situations and high ambient temperatures, steam may be injected into the gas turbine combustors to lower the flame temperature and allow increased fuel use rate, which results in increased mass flow through the gas turbine thereby increasing maximum electrical output.

The following projected operating scenario was utilized to estimate maximum annual air pollutant emissions from the new gas turbines and HRSGs.

- 4304 hours of baseload (100% load) operation per year for each gas turbine @ 60°F
- 4313 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 83 gas turbine hot start-ups per year (90 min. each)
- 28 gas turbine cold start-ups per year (256 min. each)
- 111 gas turbine shutdowns per year (23 min. each)

### 3. Air Pollution Control Strategies and Equipment

The proposed CCPP Unit 8 includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides ($NO_x$), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide ($SO_2$), and particulate matter of less than 10 microns in diameter ($PM_{10}$).

#### a. Selective Catalytic Reduction with Ammonia Injection for the Control of $NO_x$

The gas turbines and HRSG duct burners each trigger BACT for $NO_x$ emissions. The gas turbines will be equipped with dry low-$NO_x$ (DLN) combustors, which are designed to minimize $NO_x$ emissions. The HRSGs will be equipped with low-$NO_x$ duct burners, which are designed to minimize $NO_x$ emissions. In addition, the combined $NO_x$ emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level $NO_x$ emission limit of 2.5 ppmvd @ 15 % $O_2$ (one hour average).

#### b. Dry Low-$NO_x$ (DLN) Combustors and Oxidation Catalyst to Minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-$NO_x$ combustors, which are also designed to minimize CO emissions. The HRSGs will be equipped with a CO catalyst designed to catalytically oxidize the CO and POC produced from firing natural gas in the CT and duct burner. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level CO emission limit of 6.0 ppmvd @ 15 % $O_2$ and a POC level of 2.0 ppmvd @ 15 % $O_2$.

#### c. Dry Low-$NO_x$ (DLN) Combustors and the CO catalyst to minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-$NO_x$ combustors, which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with a CO catalyst to minimize CO and POC emissions.

#### d. Exclusive Use of Clean-burning Natural gas to Minimize $SO_2$ and $PM_{10}$ Emissions

The gas turbines and HRSG duct burners will utilize exclusively natural gas as a fuel to minimize $SO_2$ and $PM_{10}$ emissions. Because the emission rate of $SO_2$ depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics; the use of natural gas will result in the lowest possible emission of $SO_2$. $PM_{10}$ emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

# II Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

**Table 1** is a summary of the daily maximum regulated air pollutant emissions for the gas turbines, heat recovery steam generators (HRSGs) and cooling tower. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that will result in POC, NPOC, $NO_x$, $SO_2$, $PM_{10}$, or CO emissions in excess of 10 pounds per highest day per pollutant are subject to the BACT requirement for that pollutant.

## Table 1 Maximum Daily Regulated Air Pollutant Emissions for Baseload Operation of Proposed Sources[a] (lb./day)

| Pollutant | Source | | | |
|---|---|---|---|---|
| | S-41 CTG & S-42 HRSG[a] | S-43 CTG & S-44 HRSG[a] | S-45 Fuel Preheater[b] | S-46 Cooling Tower |
| Nitrogen Oxides (as $NO_2$) | 997 | 997 | 7.2 | |
| Carbon Monoxide | 1801 | 1801 | 2.4 | |
| Precursor Organic Compounds | 234 | 234 | 3.0 | |
| Particulate Matter ($PM_{10}$) | 312 | 312 | 1.4 | 43 |
| Sulfur Dioxide | 148 | 148 | 0.5 | |

[a]Based upon one cold start, one hot start, 16 hours of CTG/HRSG baseload operation with HRSG firing and steam injection power augmentation and 2.2 hours of CTG/HRSG baseload operation in a 24-hour period.

[b] The Fuel Preheater is operated only during starts. Operation limited to 16 hours/day.

**Table 2** is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions

shown are based upon a worst-case ammonia emission concentration of 10 ppmvd @ 15% $O_2$ due to ammonia slip from the A-11 and A-13 SCR Systems.

## Table 2
## Maximum Facility Toxic Air Contaminant (TAC) Emissions

| Toxic Air Contaminant | Pounds/year | Risk Screening Trigger Level[a] (lb./yr-source) |
|---|---|---|
| **S-41, S-42, S-43, and S-44 Combined** | | |
| Acetaldehyde[b] | 2558 | 72 |
| Acrolein | 884 | 3.9 |
| Ammonia[c] | 518,242 | 19,300 |
| Benzene[b] | 506 | 6.7 |
| 1,3-Butadiene[b] | 4 | 1.1 |
| Ethylbenzene | 670 | 193,000 |
| Formaldehyde[b] | 4102 | 33 |
| Hexane | 20,000 | 83,000 |
| Naphthalene | 62 | 270 |
| PAHs[b] | 38 | 0.043 |
| Propylene | 39,214 | none specified |
| Propylene Oxide[b] | 1780 | 52 |
| Toluene | 2706 | 38,600 |
| Xylenes | 1078 | 57,900 |
| **Cooling Tower Emissions, S-46[d]** | | |
| Arsenic[b] | 0.016 | 0.024 |
| Beryllium | 0.041 | 0.014 |
| Cadmium[b] | 0.00010 | 0.046 |
| Chromium VI[b] | 0.018 | 0.0014 |
| Copper | 0.024 | 463 |
| Lead[b] | 0.003 | 16 |
| Manganese | 0.15 | 77 |
| Mercury | 0.00007 | 57.9 |
| Nickel | 0.023 | 73 |
| Selenium | 0.002 | 97 |
| Zinc | 0.017 | 6,760 |
| **Fuel Pre-Heater, S-45** | | |
| Acetaldehyde[b] | 0.025 | 72 |
| Arsenic | 0.00056 | 0.024 |
| Benzene | 0.025 | 6.7 |
| Beryllium | 3.37E-5 | 0.014 |
| Cadmium[b] | 0.0031 | 0.046 |
| Chromium VI[b] | 0.040 | 0.0014 |
| Copper | 0.0024 | 463 |

| Toxic Air Contaminant | Pounds/year | Risk Screening Trigger Level[a] (lb./yr-source) |
|---|---|---|
| Toxic Air Contaminant | Pounds/year | Risk Screening Trigger Level[a] (lb./yr-source) |
| Formaldehyde | 0.624 | 33 |
| Hexane | 5.08 | 83,000 |
| Manganese | 0.0011 | 77 |
| Mercury | 0.0007 | 57.9 |
| Naphthalene | 0.0017 | 270 |
| Nickel | 0.006 | 73 |
| PAHs, Total | 0.00005 | 0.043 |
| Selenium | 0.00005 | 97 |
| Toluene | 0.0097 | 38,600 |
| Zinc | 0.082 | 6,760 |

[a]pursuant to BAAQMD Toxic Risk Management Policy

[b]carcinogenic compound

[c]based upon the worst-case ammonia slip of 10 ppmvd @ 15% $O_2$ from the A-11 and A-13 SCR systems with ammonia injection

[d]based on San Joaquin River water analysis and cooling tower drift rate.

**Table 3** is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of the trigger levels shown must perform modeling to assess the net air quality impact of that pollutant.

## Table 3
## Maximum Annual Facility Regulated Air Pollutant Emissions Increase

| Pollutant | Cumulative Increase Emissions[a,b] (tons/year) | PSD Trigger[c] (tons/year) |
|---|---|---|
| Nitrogen Oxides (as $NO_2$) | 174.3 | 40 |
| Carbon Monoxide | 259.1 | 100 |
| Precursor Organic Compounds | 46.6 | N/A |
| Particulate Matter ($PM_{10}$) | 112.2 | 15 |
| Sulfur Dioxide | 48.5 | 40 |

[a]Includes emissions from two gas turbines, heat recovery steam generators, natural-gas-fired preheater and cooling tower.

[b]Emissions include 28 cold startups, 83 hot startups, and 111 shutdowns, and 8,626 hours at 100% duct burner capacity with the balance of the time at 100% load at 60F.

[c]For a new major facility.

# III Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed CCPP Unit 8 will comply with those requirements.

## A. Regulation 2, Rule 2; New Source Review

The primary requirements of New Source Review that apply to the proposed CCPP Unit#8 facility are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2-302; "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR", and Section 2-2-404, "PSD Air Quality Analysis".

### 1. Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and must have been demonstrated to be effective and reliable on a full-scale unit and shown to be cost-effective on

the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The following section includes BACT determinations by pollutant for the permitted sources of the proposed CCPP Unit 8. Because each Gas Turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

**Nitrogen Oxides ($NO_x$)**

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for $NO_x$ as 2.5 ppmvd @ 15% $O_2$ with an averaging period of one hour. This BACT determination was based upon the use of SCR and Low $NO_x$ combustors or a SCONOX System. This determination is based on recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595), Delta Energy Center (Application # 19414) and Metcalf Energy Center (Application # 27215). The EPA has accepted this BACT determination as Federal LAER and further established a $NO_x$ concentration of 2.0 ppmvd @ 15% $O_2$ averaged over three hours as equivalent to 2.5 ppmvd @ 15% $O_2$, averaged over one hour. CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a $NO_x$ emission concentration limit of 2.5 ppmvd $NO_x$ @ 15% $O_2$, averaged over one hour, during all operating modes except gas turbine start-ups and shutdowns. Compliance with this emission limitation will be achieved through the use of a selective catalytic reduction (SCR) system with ammonia injection and will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. This unit will be restricted to 16 hours of operation per day, which results in a $NO_x$ emission of 7.2 lbs./day. BACT is therefore not required.

*Top-Down BACT Analysis*

In response to comments from EPA Region 9 and various intervenors, the following "top-down" BACT analysis for $NO_x$ has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual. A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring.

*Available Control Options and Technical Feasibility*

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the $SCONO_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for $NO_x$ of 2.5 ppmvd @ 15% $O_2$, averaged over one hour or 2.0 ppmvd @ 15% $O_2$, averaged over three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, has conducted "full-scale damper testing" that demonstrates that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the CCPP Unit 8 Facility. Stone & Webster Management Consultants, Inc. of Denver Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the "scale-up" of the $SCONO_x$ system for large turbines has not been demonstrated, we do not consider $SCONO_x$ to be a viable control alternative for $NO_x$.

Although we do not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and $SCONO_x$. We are providing the following analysis for informational purposes only. The analysis shown in Table 4 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a $NO_x$ emission rate of 25 ppmvd @ 15% $O_2$.

## Table 4 Top-Down BACT Analysis Summary for $NO_x$

| Control Alternative | Emissions[a] (ton/yr) | Emission Reduction[b] (ton/yr) | Total Annualized Cost[c] ($/yr) | Average Cost-Effectiveness ($/ton) | Incremental Cost-Effectiveness ($/ton) | Toxic Impacts | Adverse Environmental Impacts | Incremental Energy Impact (MM BTU/yr) |
|---|---|---|---|---|---|---|---|---|
| $SCONO_x$ | 788 | 709 | 4,122,889 | 5,815 | N/A[d] | No | No | 122,000[e] |
| SCR | 788 | 709 | 1,557,125 | 2,196 | - | Yes | No | 67,900[e] |

[a]based upon $NO_x$ emission rate of 25 ppmvd @ 15% $O_2$, and annual firing rate of 17,436,780 MM BTU/yr

[b]based upon $NO_x$ emission rate after abatement of 2.5 ppmvd @ 15% $O_2$, and annual firing rate of 17,436,780 MM BTU/yr

[c]"Cost Analysis for $NO_x$ Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d]does not apply since there is no difference in emission reduction quantity between alternatives

[e]"Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

*Energy Impacts*

As shown in Table 4, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

*Economic Impacts*

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 4, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of $NO_x$ abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for $NO_x$ of 2.5 ppmvd @ 15% $O_2$, averaged over one hour and therefore achieve the same $NO_x$ emission reduction in tons per year.

*Environmental Impacts*

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15 % $O_2$. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.003 and a chronic hazard index of 0.001 resulting from the ammonia slip emissions. In accordance with the District Toxic Risk Management Policy and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The CCPP Unit 8 Facility will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed CCPP Unit 8 Facility and found that the impact would not be significant. Therefore, the potential environmental impact due to aqueous ammonia storage at the CCPP Unit 8 Facility does not justify the elimination of SCR as a control alternative. It should be noted that aqueous ammonia, proposed for this project, is far safer than anhydrous ammonia, which is a vapor at atmospheric conditions.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

*Conclusion*

Neither SCR nor $SCONO_x$ will cause significant energy, economic or environmental impacts. If proposed by the applicant, either would be approvable by the District. The applicant's proposed use of SCR to meet the District's BACT standard for $NO_x$ is therefore acceptable.

**Carbon Monoxide (CO)**

BACT for CO will be analyzed within the context ofthree distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing. The third mode includes gas turbine firing at maximum load with HRSG duct burner firing and steam injection power augmentation at the gas turbine combustors. Steam injection power augmentation lowers the combustor flame temperature thereby allowing an increased fuel use rate, which in turn increases gas turbine peak generating capacity during periods of high ambient temperature. However, by lowering the combustor flame temperature steam injection can increase CO production.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for CO as 6 ppmvd, @ 15% $O_2$ with an averaging period of one hour. This BACT determination was based upon the use of CO Catalyst and Dry Low $NO_x$ combustors. CARB has also cited these levels as

BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

When the Crockett Cogeneration facility was originally permitted in 1993 at a CO emission concentration limit of 5.9 ppmvd @ 15% $O_2$, it established the technologically feasible/cost-effective BACT specification cited above. However, subsequent operation of the facility has shown that they cannot achieve this emission concentration under all operating modes and ambient conditions. Specifically, CO emissions exceed 5.9 ppmvd during minimum load operation under ambient conditions of low temperature and high relative humidity and during peak load operation under ambient conditions of high temperature and moderate to high relative humidity. However, Crockett Cogeneration expects that the gas turbine will comply with a CO emission concentration limit of 10 ppmvd @ 15% $O_2$ under all loads and ambient conditions with and without duct burner firing, with one exception. Crockett does not expect to consistently meet 10 ppmvd CO, when operating in steam injection power augmentation mode.

None of the three power plants recently permitted in the Bay Area expressed any problem being limited to 10 ppmvd CO, even during steam injection power augmentation mode. All have agreed to operate below 10 ppmvd during all modes of operation, except during start-up and shutdown. Two of the power plants have further agreed to operate below 6 ppmvd during all modes of operation, except during start-up and shutdown. We expect the use of newer low-NOx combustors and oxidizing catalysts to consistently meet 10 ppmvd CO, except during start-up and shutdown.

Therefore, achieved in practice BACT2 for CO is deemed to be 10 ppmvd CO @ 15% $O_2$ for the combined exhaust from the gas turbine/HRSG duct burners during all modes of operation, except during gas turbine start-up and shutdown. The applicant will typically comply with this BACT specification through the use of dry low-$NO_x$ combustors, which minimize incomplete combustion and/or through the use of an oxidation catalyst.

Two power plants in the Bay Area were recently issued permits with a CO emission concentration limit of 6.0 ppmvd @ 15% $O_2$ during all operating modes except for gas turbine start-up and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG and is predicated upon the use of an oxidation catalyst. Because the power plants proposed this limit, it was accepted as meeting BACT 1 for CO. However, it is not considered achieved-in-practice BACT since it has not yet been demonstrated in actual operation. The 6.0 ppmvd will be considered BACT 1 "technologically feasible/cost-effective BACT" for CO emissions.

The CCPP Unit 8 has agreed to a CO emission limit of 6 ppmvd @ 15% $O_2$ that will apply to all gas turbine/HRSG operating modes except for gas turbine start-up and shutdown. As is the case for Los Medanos Energy Center, this limit will apply to the firing of the turbine alone, turbine operation with HRSG duct burner firing, and steam injection power augmentation mode. The CCPP Unit 8 intends to comply with this BACT specification through the use of dry low-$NO_x$ duct burners, which minimize incomplete combustion, and

by the use of a CO oxidation catalyst. The applicant's proposed CO level of 6 ppm therefor complies with BACT.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. This unit will be restricted to 16 hours of operation per day, which results in a CO emission of 2.4 lbs./day. BACT is therefore not required.

**Precursor Organic Compounds (POCs)**

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for POC as 2 ppmvd, @ 15% $O_2$ with an averaging period of one hour. This BACT determination was based upon the use of an Oxidation Catalyst or Dry Low $NO_x$ combustors. This determination is based on recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595) and Metcalf Energy Center (Application # 27215). CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve POC emissions no greater than 3.0 lbs./day so a BACT determination is not required for this unit.

**Sulfur Dioxide ($SO_2$)**

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6 specifies BACT for $SO_2$ for gas turbines with a heat input rating $\geq$ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal $SO_2$ emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 1 grain/scf. This corresponds to an $SO_2$ emission factor of 0.0028 lb./MM Btu. The natural gas sulfur content specification of 1 grain per 100 scf is deemed BACT for $SO_2$.

- Gas-Fired Fuel Preheater

During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve $SO_2$ emissions no greater than 0.5 lbs./day based on 16 hours of operation. A BACT determination is therefore not required.

**Particulate Matter ($PM_{10}$)**

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT for $PM_{10}$ for gas turbines with a heat input rating $\geq$ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal $PM_{10}$ emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 1 grain/scf. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal direct $PM_{10}$ emissions and minimal formation of secondary $PM_{10}$ such as sulfates.

- Cooling Tower

  Southern Energy is proposing a cooling tower with a drift rate of 0.0005 %. Based on a recent BACT determination by the San Joaquin Valley Unified APCD (Guideline 8.3.10). The District considers BACT for the cooling towers to be a drift rate of 0.0006 % which will be published in BAAQMD BACT Guideline 181.1. The proposed drift rate is therefore acceptable.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve $PM_{10}$ emissions no greater than 1.4 lbs./day based on 16 hours of operation and therefore a BACT determination is not required.

## 2. Emission Offsets

### General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and $NO_x$ emission increases from permitted sources at facilities, which will emit 15 tons per year or more on a pollutant-specific basis. Because the CCPP facility will emit more than 50 tons per year of $NO_x$, offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Because CCPP will emit more than 50 tons/year of POC, offsets must be provided, by the applicant, at a ratio of 1.15 to 1.0.

Pursuant to Regulation 2-2-303, emission offsets shall be provided (at a ratio of 1.0:1.0) for $PM_{10}$ emission increases at facilities that will be permitted to emit more than 100 tons of $PM_{10}$ per year. These offsets will be required for the gas turbines, HRSGs and the cooling tower. Pursuant to Regulation 2-2-303.1, emission reduction credits of nitrogen oxides or sulfur dioxide may be used to offset $PM_{10}$ emission increases. The applicant is proposing to offset $PM_{10}$ at a ratio of 3 tons of sulfur dioxide for each ton of $PM_{10}$. This is the same ratio that that has been used for the nearby Delta Energy Center project. The APCO has determined that the same ratio is acceptable for this application.

It should be noted that in the case of POC and $NO_x$ offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset.

### Timing for Provision of Offsets

Pursuant to District Regulation 2-2-311, the applicant must "provide" the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct. Pursuant to District Regulation 2, Rule 3, "Power Plants," the Authority to Construct will be issued after the California Energy Commission issues the Certificate for the power plant. Historically, the BAAQMD has not required the applicant to provide the actual banking certificates to the District prior to the issuance of the Authority to Construct. Rather, the District has accepted the applicant's demonstration of control of valid offsets through enforceable contracts or options to purchase as equivalent to the "provision" of offsets as required by Regulation 2-2-311. The actual banking certificates must be surrendered to the District prior to the issuance of the Permit to Operate.

### Interpollutant Offset Ratios

Pursuant to District Regulation, 2-2-303.1, an applicant can provide $NO_x$ and/or $SO_2$ emission credits to offset $PM_{10}$ emission increases at ratios deemed appropriate by the APCO. Pursuant to current District policy, the default interpollutant trade-off ratios for Eastern Contra Costa County are 6 to 1 for $NO_x$ and 4 to 1 for $SO_2$. These ratios represent "conservative best-estimate values" from an interpollutant trade-off study conducted by Systems Applications International (SAI) for the Shell Refinery located in Martinez, California. More specifically, the analysis specifies a "best estimate" trade-off ratio for the Pittsburg area of 3 to 1 for $SO_2$ to $PM_{10}$. Because the

Contra Costa Unit #8 project will be located within 8 miles of the Pittsburg monitoring station the trade-off ratio of 3 tons of $SO_2$ for each ton of $PM_{10}$ will be used. Please see Appendix C, Attachment 1 for the District policy memorandum regarding this trade-off ratio.

The SAI analysis utilized three methods to estimate the amount of secondary $PM_{10}$ formation resulting from the emission of $NO_x$ and $SO_2$. The first method was based entirely upon the analysis of air quality data. The second method used a photochemical box model to compute the aerosol yield from a unit of $NO_x$ or $SO_2$ emissions. The third method used the photochemical model to simulate the effect of an incremental unit of precursor emissions on a typical atmosphere with variable mixing height. The inter-pollutant trade-off ratios generated by the SAI analysis only apply to facilities located in the eastern portion of Contra Costa County. Under current District policy, if an applicant wishes to utilize different (i.e. lower) interpollutant offset ratios, they must submit an analysis for review by the District Planning Division.

**Offset Requirements by Pollutant**

The applicable offset ratios and the quantity of offsets required are summarized in Appendix C, Table C-1.

POC Offsets

Because the combined emissions from the existing and proposed units at the CCPP facility will exceed 50 tons per year of Precursor Organic Compounds (POCs), the POC emission increases must be offset at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302.

$NO_x$ Offsets

Because the CCPP Unit 8 will emit greater than 50 tons per year of Nitrogen Oxides (as $NO_2$) from permitted sources, the applicant must provide emission reduction credits (ERCs) of $NO_x$ at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302.

$PM_{10}$ Offsets

With projected $PM_{10}$ emissions from permitted sources of greater than 100 tons per year, the CCPP Unit 8 triggers the $PM_{10}$ offset requirement of District Regulation 2-2-303. The applicant plans to offset the $PM_{10}$ with $SO_2$ credits at a ratio of 3:1.

$SO_2$ Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed $SO_2$ emission increases associated with this project since the facility $SO_2$ emissions will not exceed 100 tons per year. Regulation 2-2-303 does allow for the voluntary offsetting of $SO_2$ emission increases of less than 100 tons per year. The applicant has not opted to provide such emission offsets.

**Current Proposed Offset Package**

**Table 5** summarizes the current offset obligation of the CCPP Unit 8 and the quantity of valid emission reduction credits (ERCs) under the control of Southern Energy. The emission reduction credits presented in **Table 5** exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, "Emissions Banking", and were subsequently issued as a banking certificate by the BAAQMD.

As indicated, Southern Energy has secured sufficient valid emission reduction credits to offset the emission increases from the permitted sources proposed for the CCPP Unit 8.

## Table 5
## Emission Reduction Credits Identified by Southern Energy (ton/yr)

| | POC[a] | $NO_x$[b] | $PM_{10}$[c] |
|---|---|---|---|
| Valid Emission Reduction Credits | 53.6 | 200.5 | 112.2 |
| Permitted Source Emission Limits | 46.6 | 174.3 | 112.2 |
| Offsets Required per BAAQMD Calculations | 53.6[d] | 200.5[d] | 112.2[e] |

[a]From Banking Certificate # 693.

[b]From Banking Certificate # 693.

[c]$SO_2$ used at a ratio of 3:1. The following $SO_2$ Banking Certificates used:

#693 321.90 tons

#694 14.53 tons

#695 0.17 tons

**Total 336.60 tons** ($PM_{10}$ equivalent 112.2 tons)

[d]Reflects applicable offset ratio of 1.15:1.0 pursuant to Regulation 2-2-302

[e]Reflects applicable offset ratio of 1.0:1.0 pursuant to Regulation 2-2-302

These Banking Certificates originated from the following locations:

| Certificate | Company | Location | Original Issue Dates |
|---|---|---|---|
| #693 | Gaylord Container | Antioch | 6/8/84, 3/12/90, 7/15/93 |
| #694 | P G & E | Martinez | 7/22/87 |
| #695 | Hudson ICS | San Leandro | 4/9/97 |

## 3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the CCPP Unit#8 project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the CCPP Unit#8 facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for $NO_2$, CO, and $PM_{10}$ or an exceedence of any applicable PSD increment. **Table 6** summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution from the proposed CCPP Unit#8.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation.

**Table 6**
**California and National Ambient Air Quality Standards and Ambient Air Quality Levels from the Proposed CCPP Unit#8 ($\mu g/m^3$)**

| Pollutant | Averaging Time | Maximum Background | Maximum Project impact | Maximum Project impact plus maximum background | California Standards | National Standards |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-hour | 164 | 225 | 389 | 470 | --- |

Please see Appendix E for a detailed discussion of the PSD air quality impact analysis.

## B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the CCPP Unit#8 project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the CCPP Unit#8 are summarized in **Table 7**. In accordance with the requirements of the BAAQMD Toxic Risk Management Policy (TRMP) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

## Table 7 Health Risk Assessment Results

| Source | Multi-pathway Carcinogenic Risk (risk in one million) | Non-carcinogenic Chronic Hazard Index | Non-carcinogenic Acute Hazard Index[a] |
|---|---|---|---|
| Gas Turbines, HRSGs, and Cooling Tower[b] | 0.67 | 0.04 | 0.2 |

[a]included for informational purposes only; BAAQMD TRMP does not require an assessment of acute (short-term; i.e. < 24 hour) health impacts

[b]numbers represent combined risk from all sources

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to the BAAQMD Risk Management Policy, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. The chronic hazard index attributed to the emission of non-carcinogenic air contaminants is considered to be not significant since it is less than 1.0. Therefore, the CCPP Unit#8 facility is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. Please see Appendix D for further detail.

## C. Other Applicable District Rules and Regulations

**Regulation 1, Section 301: Public Nuisance**

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis insures that the proposed facility will comply with this Regulation.

**Regulation 2, Rule 1, Sections 301 and 302:**
**Authority to Construct and Permit to Operate**

Pursuant to Regulation 2-1-301 and 2-1-302, the CCPP Unit 8 has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-41 & S-43 Gas Turbines, S-42 & S-44 Heat Recovery Steam Generators, S-45 Fuel Preheater and S-46 Cooling Tower.

**Regulation 2, Rule 3: Power Plants**

Pursuant to Regulation 2-3-403, this Final Determination of Compliance (FDOC) serves as the APCO's Final decision that the proposed power plant will meet the requirements of all applicable

BAAQMD, state, and federal regulations. The FDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-304, this FDOC has fulfilled the requirements for public notice, public comment, and public inspection contained in Regulation 2-2-406 and 407.

**Regulation 2, Rule 6: Major Facility Review**

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the CCPP Unit#8 shall submit an application to the BAAQMD for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Regulation 2-6-212.1, the CCPP Unit#8 will become subject to Regulation 2, Rule 6 upon initial firing of any of the gas turbines (S-41 & S-43) or HRSGs (S-42 & S-44).

**Regulation 2, Rule 7: Acid Rain**

The CCPP Unit 8 gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), CCPP Unit#8 must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. Pursuant to 40 CFR Part 72.2, "commence operation" includes the start-up of the unit's combustion chamber.

**Regulation 6: Particulate Matter and Visible Emissions**

Through the use of dry low-$NO_x$ burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines and HRSG duct burners is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the simultaneous operation of each power train (CTG and HRSG Duct Burners) is 0.0022 gr./dscf @ 6% $O_2$. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 5666 mg/l and corresponding maximum $PM_{10}$ emission rate of 1.77 lb./hr, the proposed exempt 10-cell cooling tower is expected to comply with the requirements of Regulation 6.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. It is expected that the California Energy Commission will impose conditions on construction activities that will require the use of water and/or chemical dust suppressants to minimize $PM_{10}$ emissions and prevent visible particulate emissions.

**Regulation 7: Odorous Substances**

Regulation 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the two proposed CTG/HRSG power trains will each be limited by permit condition to 10 ppmvd @ 15% $O_2$, the facility is expected to comply with the requirements of Regulation 7.

**Regulation 8: Organic Compounds**

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at the CCPP Unit#8.

The use of solvents for cleaning and maintenance at the CCPP Unit#8 is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

**Regulation 9: Inorganic Gaseous Pollutants**

Regulation 9, Rule 1, Sulfur Dioxide

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level $SO_2$ concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits $SO_2$ emissions in excess of 300 ppmv (dry). With maximum projected $SO_2$ emissions of < 1 ppmv, the gas turbines and HRSG duct burners are not expected to contribute to noncompliance with ground level $SO_2$ concentrations and should easily comply with section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The proposed combustion gas turbines (each rated at 1,872 MM Btu/hr HHV) shall comply with the Regulation 9-3-303 $NO_x$ limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.5 ppmvd @ 15% $O_2$. The HRSG duct burners will also be limited to 2.5 ppmvd and therefor comply with this regulation.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed HRSGs are exempt from Regulation 9, Rule 7, per section 110.5 since they are used to recover sensible heat from the exhaust of the proposed combustion turbines.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the proposed combustion gas turbines and HRSGs will be limited by permit condition to $NO_x$ emissions of 2.5 ppmvd @ 15% $O_2$, they are expected to comply with the Regulation 9-9-301.3 $NO_x$ limitation of 9 ppmvd @ 15% $O_2$.

## D. CEQA

The CEQA requirements of regulation 2-1-426 are met because the California Energy Commission (CEC) has taken the lead agency roll on this project and are responsible for the EIR, which will fulfill the CEQA requirement. The Application for Certification that the applicant has submitted to the CEC serves as the EIR.

## E. MACT

The federal Clean Air Act, Section 112(g), requires that any facility than emits more than 10 tons/year of a HAP (Hazardous Air Pollutant) or 25 tons/year aggregate must do a MACT (Maximum Available Control Technology) determination. The estimated HAP emissions for this facility have been added to Table B-6, the toxic emission summary, in Appendix B. As can be seen in this table, many of the toxics listed are not on the federal HAP list. This table indicates that the HAP emissions are below the MACT trigger levels. Initial calculations from the applicant indicated that the hexane emissions were over 33 tons/year but because of the origin of the hexane emission factor (described in Appendix A) the applicant and the District agreed that the actual hexane emissions can be expected to be much lower than 33 tons/year. The source tests the original hexane emission factor was derived from are from three gas turbines that were tested in Ventura County in 1994. A review of these tests disclosed that in all cases hexane was non-detect (below the instrument range). The emission factor was apparently calculated assuming the detection limit as the concentration. This was a very conservative approach and will overstate the emissions. The District and the applicant are confident that the annual hexane emissions will be below the federal MACT trigger of 10 tons/year. A condition has been added to limit the hexane emissions to 10 tons/year and verification by source test is required.

The District concludes that a MACT determination is not necessary for this facility.

# IV Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb./hr and lb./MM Btu of natural gas fired) will ensure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and $NO_x$ limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. If the CO and $NO_2$ CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable gas content and the differing response times of the gas monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, $SO_2$, and $PM_{10}$ mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to as designed operation of each CTG/HRSG power train and the auxiliary boilers, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and oxidation catalysts fully operational. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 1 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedence of any short-term applicable ambient air quality standard.

## CCPP Unit 8
## Permit Conditions

**Definitions:**

| | |
|---|---|
| 1-hour period: | Any continuous 60-minute period beginning on the hour. |
| Calendar Day: | Any continuous 24-hour period beginning at 12:00 AM or 0000 hours. |
| Year: | Any consecutive twelve-month period of time |
| Heat Input: | All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in Btu/scf. |
| Rolling 3-hour period: | Any three-hour period that begins on the hour and does not include start-up or shutdown periods. |

| | |
|---|---|
| Firing Hours: | Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments. |
| MM Btu: | million British thermal units |
| Gas Turbine Start-up Mode: | The lesser of the first 256 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 27(b) and 27(d). |
| Gas Turbine Shutdown Mode: | The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 27(b) through 27(d) until termination of fuel flow to the Gas Turbine. |
| Specified PAHs: | The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.<br>Benzo[a]anthracene<br>Benzo[b]fluoranthene<br>Benzo[k]fluoranthene<br>Benzo[a]pyrene<br>Dibenzo[a,h]anthracene<br>Indeno[1,2,3-cd]pyrene |
| Corrected Concentration: | The concentration of any pollutant (generally $NO_x$, CO, or $NH_3$) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% $O_2$ by volume on a dry basis. |
| Commissioning Activities: | All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the CCPP Unit#8 construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems. |
| Commissioning Period: | The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange. |

| | |
|---|---|
| Precursor Organic Compounds (POCs): | Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate |
| CEC CPM: | California Energy Commission Compliance Program Manager |
| CCPP Unit#8: | Contra Costa Power Plant Unit 8 |

**Conditions for the Commissioning Period**

1. The owner/operator of the CCPP Unit 8 (CCPP Unit#8) shall minimize emissions of carbon monoxide and nitrogen oxides from S-41 and S-43 Gas Turbines and S-42 and S-44 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period. Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 47 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-41 & S-43 Gas Turbine combustors and S-42 & S-44 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-11 and A-13 SCR Systems and A-12 and A-14 CO Oxidation Catalyst Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-41 & S-43 Gas Turbines and S-42 & S-44 Heat Recovery Steam Generators.

4. Coincident with the as designed operation of A-11 & A-13 SCR Systems, pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall comply with the $NO_x$ and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the CCPP Unit#8 shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired preheater. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-$NO_x$ combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and $NO_x$ continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

6. During the commissioning period, the owner/operator of the CCPP Unit#8 shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   firing hours for each gas turbine and each HRSG
   fuel flow rates to each train
   stack gas nitrogen oxide emission concentrations at P-11 and P-12
   stack gas carbon monoxide emission concentrations P-11 and P-12
   stack gas carbon dioxide concentrations P-11 and P-12

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44). The owner/operator shall use District-approved methods to calculate heat input rates, $NO_x$ mass emission rates, carbon monoxide mass emission rates, and $NO_x$ and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous emission monitors specified in condition 6 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44). After first firing of the turbines, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and $NO_x$ emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-41 Gas Turbine and S-42 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-11 SCR System and/or A-12 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-41 Gas Turbine and S-42 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

9. The total number of firing hours of S-43 Gas Turbine and S-44 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-13 SCR System and/or A-14 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-43 Gas Turbine and S-44 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, $PM_{10}$, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

11. Combined pollutant mass emissions from the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-41 & S-43).

| | | |
|---|---|---|
| $NO_x$ (as $NO_2$) | 8,400 pounds per calendar day | 400 pounds per hour |
| CO | 13,000 pounds per calendar day | 584 pounds per hour |
| POC (as $CH_4$) | 535 pounds per calendar day | |
| $PM_{10}$ | 624 pounds per calendar day | |
| $SO_2$ | 297 pounds per calendar day | |

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 20. The source test shall determine $NO_x$, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

**Conditions for the Gas Turbines (S-41 & S-43) and the Heat Recovery Steam Generators (HRSGs; S-42 & S-44)**

13. The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on natural gas. (BACT for $SO_2$ and $PM_{10}$)

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,227 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for $NO_x$)

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 49,950 MM Btu per calendar day. (PSD for $PM_{10}$)

16. The combined cumulative heat input rate for the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall not exceed 34,900,000 MM Btu per year. (Offsets)

17. The HRSG duct burners (S-42 and S-44) shall not be fired unless its associated Gas Turbine (S-41 and S-43, respectively) is in operation. (BACT for $NO_x$)

18. Except as provided in Condition No. 8, S-41 Gas Turbine and S-42 HRSG shall be abated by the properly operated and properly maintained A-11 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-11 catalyst bed has reached minimum operating temperature. (BACT for $NO_x$)

19. Except as provided in Condition No. 9, S-43 Gas Turbine and S-44 HRSG shall be abated by the properly operated and properly maintained A-13 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-13 catalyst bed has reached minimum operating temperature. (BACT for $NO_x$)

20. The Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as $NO_2$) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as $NO_2$) at P-12 (the combined exhaust point for the S-43 Gas Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. (PSD for $NO_x$)

    (b) The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any 1-hour period. (BACT for $NO_x$)

    (c) Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed 0.013 lb./MM Btu (HHV) of natural gas fired or 29.22 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed 6 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any rolling 3-hour period. (BACT for CO)

    (e) Ammonia ($NH_3$) emission concentrations at P-11 and P-12 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (TRMP for $NH_3$)

(f) Precursor organic compound (POC) mass emissions (as $CH_4$) at P-11 and P-12 each shall not exceed 5.6 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)

(g) Sulfur dioxide ($SO_2$) mass emissions at P-11 and P-12 each shall not exceed 6.18 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)

(h) Particulate matter ($PM_{10}$) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or 0.00588 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter ($PM_{10}$) mass emissions at P-11 and P-12 each shall not exceed 13 pounds per hour or 0.00584 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-41 and S-43) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

| | Cold Start-Up (lb./start-up) | Hot Start-Up (lb./start-up) | Shutdown (lb./shutdown) |
|---|---|---|---|
| Oxides of Nitrogen (as $NO_2$) | 452 | 189 | 59 |
| Carbon Monoxide (CO) | 990 | 291 | 73 |
| Precursor Organic Compounds (as $CH_4$) | 109 | 26 | 6 |

22. The Gas Turbines (S-41 and S-43) shall not be in start-up mode simultaneously. (PSD)

23. Total combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44), including emissions generated during Gas Turbine start-ups and shutdowns shall not exceed the following limits during any calendar day:

| | | |
|---|---|---|
| (a) | 1,994 pounds of $NO_x$ (as $NO_2$) per day | (CEQA) |
| (b) | 3,602 pounds of CO per day | (PSD) |
| (c) | 468 pounds of POC (as $CH_4$) per day | (CEQA) |
| (d) | 624 pounds of $PM_{10}$ per day | (PSD) |
| (e) | 297 pounds of $SO_2$ per day | (BACT) |

24. Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44)and the Fuel Gas Preheater (S-45) and the Cooling Tower (S-46), including emissions generated during gas turbine start-ups and shutdowns shall not exceed the following limits during any consecutive twelve-month period:

| | | |
|---|---|---|
| (a) | 174.3 tons of $NO_x$ (as $NO_2$) per year | (Offsets, PSD) |
| (b) | 259.1 tons of CO per year | (Cumulative Increase) |
| (c) | 46.6 tons of POC (as $CH_4$) per year | (Offsets) |
| (d) | 112.2 tons of $PM_{10}$ per year | (Offsets, PSD) |
| (e) | 48.5 tons of $SO_2$ per year | (Cumulative Increase) |

25. Toxic and HAP Emission Limits

25.1. The maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limits:

4,102 pounds of formaldehyde per year
506 pounds of benzene per year
38 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

25.2. The maximum projected annual Hazardous Air Pollutant (HAP) emissions from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limit:

20,000 pounds of hexane per year
(US-CAA, Section 112(g))

Conformance with this limit shall be verified by the source testing in condition 32.

26. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 23(a), 23(b), 24(a), and 24(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(b) Carbon Dioxide ($CO_2$) or Oxygen ($O_2$) concentrations, Nitrogen Oxides ($NO_x$) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.
(c) Ammonia injection rate at A-11 and A-13 SCR Systems
(d) Steam injection rate at S-41 & S-43 Gas Turbine Combustors

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing

hours, the average hourly fuel flow rates, and average hourly pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(e) Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

(f) Corrected $NO_x$ concentrations, $NO_x$ mass emissions (as $NO_2$), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.

Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and (26f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-41, S-42, S-43, and S-44) combined.

(i) the average $NO_x$ mass emissions (as $NO_2$), CO mass emissions, and corrected $NO_x$ and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(j) on an hourly basis, the cumulative total $NO_x$ mass emissions (as $NO_2$) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.

(k) For each calendar day, the average hourly Heat Input Rates, Corrected $NO_x$ emission concentrations, $NO_x$ mass emissions (as $NO_2$), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

(l) on a daily basis, the cumulative total $NO_x$ mass emissions (as $NO_2$) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c) through 23(e), and 24(c) through 24(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter ($PM_{10}$) mass emissions (including condensable particulate matter), and Sulfur Dioxide ($SO_2$) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 26, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, $PM_{10}$, and $SO_2$ emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-41, S-42, S-43, and S-44) combined.

(b) on a daily basis, the 365 day rolling average cumulative total POC, $PM_{10}$, and $SO_2$ mass emissions, for all four sources (S-41, S-42, S-43, and S-44) combined.

(Offsets, PSD, Cumulative Increase)

28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of Formaldehyde, Benzene, and Specified PAHs. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 34,900,000 MM Btu/year and the highest emission factor (pounds of pollutant per MM Btu of Heat Input) determined by any source test of the S-41 & S-43 Gas Turbines and/or S-42 & S-44 Heat Recovery Steam Generators. If this calculation method results in an unrealistic mass emission rate (the highest emission factor occurs at a low firing rate) the applicant may use an alternate calculation, subject to District approval. (TRMP)

29. Within 60 days of start-up of the CCPP Unit#8, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 to determine the corrected ammonia ($NH_3$) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding $NH_3$ emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve $NO_x$ emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

30. Within 60 days of start-up of the CCPP Unit#8 and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as $NO_2$), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter ($PM_{10}$) emissions including condensable particulate matter. (BACT, offsets)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's

Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total $PM_{10}$ emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 60 days of start-up of the CCPP Unit#8 and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 28 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

| | | |
|---|---|---|
| Benzene | $\leq$ | 26.8 pounds/year |
| Formaldehyde | $\leq$ | 132 pounds/year |
| Specified PAHs (TRMP) | $\leq$ | 0.18 pounds/year |

33. The owner/operator of the CCPP Unit#8 shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

34. The owner/operator of the CCPP Unit#8 shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

35. The owner/operator of the CCPP Unit#8 shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

36. The stack height of emission points P-11 and P-12 shall each be at least 195 feet above grade level at the stack base. (PSD, TRMP)

37. The Owner/Operator of CCPP Unit#8 shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval.
(Regulation 1-501)

38. Within 180 days of the issuance of the Authority to Construct for the CCPP Unit#8, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 26, 29, 30 and 32. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

39. Prior to the issuance of the BAAQMD Authority to Construct for the CCPP Unit 8, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and 112.2 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

40. Prior to the start of construction of the CCPP Unit 8, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and 112.2 tons of Particulate Matter less than 10 microns. (Offsets)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of the CCPP Unit#8 shall submit an application to the BAAQMD for a significant revision to the Major Facility Review Permit prior to commencing operation. (Regulation 2-6-404.3)

42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the CCPP Unit 8 shall not operate either of the gas turbines until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Regulation 2, Rule 7)

43. The CCPP Unit 8 shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

44. The owner/operator shall take monthly samples of the natural gas combusted at the CCPP Unit#8. The samples shall be analyzed for sulfur content using District-approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. Sulfur content shall be no more than 1.0 grains/100scf. (cumulative increase)

45. The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum

guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 5,666 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

46. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the CCPP Unit 8, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. The CEC CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the $PM_{10}$ emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD)

47. The Fuel Gas Preheater (S-45) shall not be operated more than 16 hours in any day. (BACT)

# V Recommendation

The APCO has concluded that the proposed CCPP Unit 8 power plant, which is composed of the permitted sources listed below, complies with all applicable District rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

**S-41 Combustion Gas Turbine #1, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.**

**S-42 Heat Recovery Steam Generator #1, 395 MM Btu per hour, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.**

**S-43 Combustion Gas Turbine #2, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.**

**S-44 Heat Recovery Steam Generator #2, 395 MM Btu per hour, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.**

**S-45 Gas-Fired Fuel Preheater, 12 MM Btu per hour.**

**S-46 10-Cell Wet Cooling Tower, 125,000 gallons per minute**

Pursuant to District Regulation 2-3-404, this document has fulfilled the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. A notice inviting written public comment was published in the Contra Costa Times on November 1, 2000. The public comment period ended on December 1, 2000.

Ellen Garvey
Air Pollution Control Officer/Executive Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109

# FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

**SECTION A**: FUEL DATA

| | *Fuel Name* | *Fuel Code*** | *Total Annual Usage**** | *Maximum Possible Fuel Use Rate* | *Typical Heat Content* | *Sulfur Content* | *Nitrogen Content (optional)* | *Ash Content (optional)* |
|---|---|---|---|---|---|---|---|---|
| 1. | natural gas | 189 | 174.5 E6 | 395 E6 | | | | |
| 2. | | | (total, including CTG) | (HRSG only) | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |
| 5. | | | | | | | | |

| *Use the appropriate units for each fuel* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Natural Gas | therm* | Btu/hr | N/A | N/A | N/A | N/A |
| | Other Gas | MSCF* | MSCF/hr | Btu/MSCF | ppm | N/A | N/A |
| | Liquid | m gal* | m gal/hr | Btu/m gal | wt% | wt% | wt% |
| | Solid | ton | ton/hr | Btu/ton | wt% | wt% | wt% |

**SECTION B**: EMISSION FACTORS (optional)

| | **Fuel Name** | ***Fuel Code**** | **Particulates** | | **NOx** | | **CO** | |
|---|---|---|---|---|---|---|---|---|
| | | | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* |
| 1. | | | | | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |

*Use the appropriate units for each fuel:* *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
*Solid = lb/ton*

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***Note:*** * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

| ****Fuel Codes** | | | | ****Basis Codes** | |
|---|---|---|---|---|---|
| ***Code*** | ***Fuel*** | ***Code*** | ***Fuel*** | ***Code*** | ***Method*** |
| 25 | Anthracite coal | 189 | Natural Gas | 0 | Not applicable for this pollutant |
| 33 | Bagasse | 234 | Process gas - blast furnace | 1 | Source testing or other measurement by plant (attach copy) |
| 35 | Bark | 235 | Process gas - CO | 2 | Source testing or other measurement by BAAQMD (give date) |
| 43 | Bituminous coal | 236 | Process gas - coke oven gas | 3 | Specifications from vendor (attach copy) |
| 47 | Brown coal | 238 | Process gas - RMG | 4 | Material balance by plant using engineering expertise and knowledge of process |
| 242 | Bunker C fuel oil | 237 | Process gas - other | 5 | Material balance by BAAQMD |
| 80 | Coke | 242 | Residual oil | 6 | Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA) |
| 89 | Crude oil | 495 | Refuse derived fuel | 7 | Taken from literature, other than AP-42 (attach copy) |
| 98 | Diesel oil | 511 | Landfill gas | 8 | Guess |
| 493 | Digester gas | 256 | Solid propellant | | |
| 315 | Distillate oil | 466 | Solid waste | | |
| 392 | Fuel oil #2 | 304 | Wood - hogged | | |
| 551 | Gasoline | 305 | Wood - other | | |
| 158 | Jet fuel | 198 | Other - gaseous fuels | | |
| 160 | LPG | 200 | Other - liquid fuels | | |
| 165 | Lignite | 203 | Other - solid fuels | | |
| 167 | Liquid waste | | | | |
| 494 | Municipal solid waste | | | | |

*(revised: 6/01)*

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
*Website: www.baaqmd.gov*

**Data Form C**
**FUEL COMBUSTION SOURCE**

*(for District use only)*

| | | |
|---|---|---|
| | | |

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Gateway Generating Station — Plant No: 18143 — Source No. S-45
2. Equipment Name & Number, or Description: natural gas-fired dewpoint heater
3. Make, Model : GasTech — Maximum firing rate: 6.5 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☐ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☑ process heat; material heated natural gas fuel
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

**Internal combustion** Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☐ gas turbine
☐ other _____ _____hp

**Incinerator** ☐ salvage operation ☐ pathological waste Temperature _____°F
☐ liquid waste ☐ other _____ Residence time _____Sec

**Others** ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: _____
☐ open burning ☐ kiln
☑ other natural gas fuel preheater

8. Overfire air? ☐ yes ☐ no If yes, what percent _____%
9. Flue gas recirculation? ☑ yes ☐ no If yes, what percent _____%
10. Air preheat? ☐ yes ☐ no Temperature _____°F
11. Low $NO_X$ burners? ☐ yes ☐ no Make, Model _____
12. Maximum flame temperature _____°F
13. Combustion products: Wet gas flowrate 1964 acfm at 300 °F
Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S _____ S _____ S _____ S _____ S _____ S _____ A _____ A _____ A _____
With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S _____ S _____ A _____ A _____ P 13 P _____

Person completing this form: Nancy Matthews — Date: 11/27/07

*(revised 4/05)*

# FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

**SECTION A**: FUEL DATA

| | *Fuel Name* | *Fuel Code*** | *Total Annual Usage**** | *Maximum Possible Fuel Use Rate* | *Typical Heat Content* | *Sulfur Content* | *Nitrogen Content (optional)* | *Ash Content (optional)* |
|---|---|---|---|---|---|---|---|---|
| 1. | natural gas | 189 | 569,400 | 6.5 E6 | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |
| 5. | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| *Use the appropriate units for each fuel* | Natural Gas | therm* | Btu/hr | N/A | N/A | N/A | N/A |
| | Other Gas | MSCF* | MSCF/hr | Btu/MSCF | ppm | N/A | N/A |
| | Liquid | m gal* | m gal/hr | Btu/m gal | wt% | wt% | wt% |
| | Solid | ton | ton/hr | Btu/ton | wt% | wt% | wt% |

**SECTION B**: EMISSION FACTORS (optional)

| | Fuel Name | *Fuel Code*** | Particulates | | NOx | | CO | |
|---|---|---|---|---|---|---|---|---|
| | | | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* |
| 1. | | | | | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |

*Use the appropriate units for each fuel:* *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
*Solid = lb/ton*

---

***Note:*** * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

| **Fuel Codes | | | | **Basis Codes | |
|---|---|---|---|---|---|
| *Code* | *Fuel* | *Code* | *Fuel* | *Code* | *Method* |
| 25 | Anthracite coal | 189 | Natural Gas | 0 | Not applicable for this pollutant |
| 33 | Bagasse | 234 | Process gas - blast furnace | 1 | Source testing or other measurement by plant (attach copy) |
| 35 | Bark | 235 | Process gas - CO | 2 | Source testing or other measurement by BAAQMD (give date) |
| 43 | Bituminous coal | 236 | Process gas - coke oven gas | 3 | Specifications from vendor (attach copy) |
| 47 | Brown coal | 238 | Process gas - RMG | 4 | Material balance by plant using engineering expertise and knowledge of process |
| 242 | Bunker C fuel oil | 237 | Process gas - other | 5 | Material balance by BAAQMD |
| 80 | Coke | 242 | Residual oil | 6 | Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA) |
| 89 | Crude oil | 495 | Refuse derived fuel | 7 | Taken from literature, other than AP-42 (attach copy) |
| 98 | Diesel oil | 511 | Landfill gas | 8 | Guess |
| 493 | Digester gas | 256 | Solid propellant | | |
| 315 | Distillate oil | 466 | Solid waste | | |
| 392 | Fuel oil #2 | 304 | Wood - hogged | | |
| 551 | Gasoline | 305 | Wood - other | | |
| 158 | Jet fuel | 198 | Other - gaseous fuels | | |
| 160 | LPG | 200 | Other - liquid fuels | | |
| 165 | Lignite | 203 | Other - solid fuels | | |
| 167 | Liquid waste | | | | |
| 494 | Municipal solid waste | | | | |

*(revised: 6/01)*

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street, San Francisco, CA 94109
Engineering Division (415) 749-4990
www.baaqmd.gov fax (415) 749-5030

**Form ICE**
Internal Combustion Engines

| | | |
|---|---|---|
| | | |

*Form ICE is to be completed for all internal combustion engines except turbines. (For turbines, submit Form C). Submit one form for each engine. If this is a new engine or a modification to an existing engine, you must also complete Form HRSA Health Risk Screen Analysis. Additional forms and all District regulations and rules are available on the District's web site. Contact your assigned permit engineer or the Engineering Division at the above telephone number if you need assistance completing this form. Please include the engine manufacturer's* ***equipment specifications****.*

**1. SUMMARY** ☑ New Construction ☐ Modification ☐ Loss of Exemption

Company Name: Gateway Generating Station — Plant No.*: 18143

Source Description: fire pump engine — Source No.*: S-48

Initial Date of Operation: August 2008 *(Not required for modification of an existing permitted source)* *(If unknown leave blank)

Operating Schedule: *Typical hrs/day* 1 *Days/week* 1 *Weeks/yr* 50 *Maximum hrs/day* unk

**2. ENGINE INFORMATION** ☐ *Check here if applying for a portable equipment permit. (See Reg. 2-1-413 for requirements)*

Engine Type: *(Check one)* ☑ 4 Stroke ☐ 2 Stroke Compression Ignition (Diesel) or ☐ 4 Stroke ☐ 2 Stroke Spark Ignition

Engine Manufacturer: John Deere Model: JW6H-UF40 Model Year: 2007

EPA/CARB Engine Family Name: 6081 Series Engine Serial No.: tbd

Engine Displacement: 496 *(cu in)* Maximum rated output *(bhp)*: 300 Typical load as % of bhp rating: 100

Is this an emergency/standby engine? ☑ Yes ☐ No

*(Complete and check all that apply)*

Certification: ☐ EPA Certified ☑ CARB Certified CARB Executive Order No. U-R-004-0264

☐ None *(If None is checked, please indicate below the items applicable to this engine.)*

☐ Naturally aspirated ☐ Supercharged ☐ Turbocharged ☐ Inter-cooled ☐ After-cooled

☐ Timing retard ≥ 4° ☐ Lean-burn ☐ Rich-burn

Primary Use: ☐ Electrical generation ☐ Cogeneration ☐ Pump driver ☑ Fire pump driver

☐ Compressor driver ☐ Tub grinder driver ☐ Other: _____

**3. ABATEMENT DEVICE INFORMATION** *Complete this section only if the engine exhausts to an add-on abatement device.*
☐ *Check here if the engine has more than one add-on abatement device and complete a separate Form A for each additional abatement device.*

Abatement device number A _____ *(If unknown leave blank)* ☐ New ☐ Existing

Device type: ☐ Diesel catalyzed particulate filter ☐ Oxidation catalyst ☐ Selective catalytic reduction (SCR)

☐ Non-selective catalytic reduction (NSCR or 3-way catalyst) ☐ Other: _____

Make, Model, and Rated Capacity _____

Abatement device control efficiencies at typical operation *(Use the basis codes listed below. If unknown leave blank)*

Control Efficiency/Emission Factor Basis Codes: *(Submit supporting documentation if available)*

(1) Source testing or other measurement by plant
(2) Source testing or measurement by BAAQMD *(District use only)*
(3) Specification from vendor
(4) Material balance by plant using knowledge of process
(5) Material balance by BAAQMD *(District use only)*
(6) EPA Document AP-42 Emission Factors
(7) Taken from literature other than AP-42
(8) Guess
(9) EPA/CARB Certification

| Pollutant Name | Wt % Reduction | Basis Code |
|---|---|---|
| Particulates | | |
| Organics | | |
| Nitrogen Oxides | | |
| Sulfur Dioxide | | |
| Carbon Monoxide | | |
| Others – ☐ Check here and attach a separate list of pollutants. Include the basis code and the control efficiency. | | |

Continued on reverse side

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**

**Form ICE**
Internal Combustion Engines

**4. EMISSION POINT/STACK INFORMATION** ☐ *Check here if the engine has more than one stack or has a continuous pollutant emission monitor and complete one Form P for each emission point.*

Emission point number P 18 *(If unknown leave blank)* ☑ New ☐ Existing

Stack outlet height from ground level *(ft)* 10.67

Diameter of stack outlet *(inches)* 6.065 or Outlet cross-section area *(square inches)* _____

Direction of outlet *(check one)* ☑ Horizontal ☐ Vertical End of outlet *(check one)* ☑ Open/hinged flap ☐ Rain cap

Exhaust rate at typical operation *(acfm)* 1740 Exhaust temperature at typical operation *(°F)* 770

**5. RISK ASSESSMENT INFORMATION**

Distance from engine to the property line of the nearest residence *(ft)* 4200 or *(check if)* ☐ Greater than one mile

Distance from engine to the property line of the nearest school[1] *(ft)* _____ or *(check if)* ☑ Greater than 1000 ft

Describe the nearest non-residential, non-school site *(check one)* ☑ Industrial ☐ Commercial ☐ Hospital

☐ Day care center ☐ Other _____

Distance from engine to the property line of the nearest non-residential, non- school site*(ft)* 0 or ☐ Greater than one mile

1. *K-12 and more than twelve children only.*

**6. FUEL DATA** *Complete the table below for each fuel burned. If you are using a fuel other than those listed in the fuel code table, attach a fuel analysis indicating the higher heating value, sulfur content, and nitrogen content. Please clearly indicate the measurement unit that corresponds to the information you are submitting.* ☐ *Check here if you are using more than two fuels, and attach a copy of this page listing the additional fuels.*

**Primary Fuel**

Fuel Code[1] 98 Name CARB Diesel

Maximum Fuel Use Rate[2] 14.0 *gal/hr or SCF/hr*

Annual Fuel Usage[3] 700 *gal/yr or therm/yr or SCF/yr*

Typical Heat Content[4] 136,900 *BTU/gal or BTU/SCF*

Sulfur Content[4] 0.0015 *wt% liquids or ppmv gases*

Emission Factors *(Optional)*

| Pollutant Name | Emission Factor | Units[5] | Basis Code[6] | Abated Factor (√)[7] |
|---|---|---|---|---|
| Particulates | 0.12 | g/bhp-hr | 3 | ☐ |
| Organics | 0.29 | g/bhp-hr | 3 | ☐ |
| Nitrogen Oxides | 4.36 | g/bhp-hr | 3 | ☐ |
| Carbon Monoxide | 0.32 | g/bhp-hr | 3 | ☐ |

Others – ☐ Check here and attach a separate list under each fuel used.

**Secondary Fuel**

Fuel Code[1] _____ Name _____

Maximum Fuel Use Rate[2] _____ *gal/hr or SCF/hr*

Annual Fuel Usage[3] _____ *gal/yr or therm/yr or SCF/yr*

Typical Heat Content[4] _____ *BTU/gal or BTU/SCF*

Sulfur Content[4] _____ *wt% liquids or ppmv gases*

Emission Factors *(Optional)*

| Pollutant Name | Emission Factor | Units[5] | Basis Code[6] | Abated Factor (√)[7] |
|---|---|---|---|---|
| Particulates | | | | ☐ |
| Organics | | | | ☐ |
| Nitrogen Oxides | | | | ☐ |
| Carbon Monoxide | | | | ☐ |

Others – ☐ Check here and attach a separate list under each fuel used.

1. *Fuel Codes:* Diesel (98) Bio Diesel B100 (815) Bio Diesel B20 Blend (816) Gasoline (551) Natural Gas (189) Landfill Gas (511) Digester Gas (493) Liquid Petroleum Gas (LPG) (160)
2. *Maximum fuel use rate units: gallon/hr for liquid fuels and SCF/hr for gaseous fuels. (SCF =Standard Cubic Foot)*
3. *The annual fuel usage is the actual or projected engine fuel consumption over a rolling 12-month time period. Annual usage units: gallons for liquid fuel, therms for natural gas, and SCF for other gaseous fuels. (therm = 100,000 BTUs, BTU =British Thermal Unit)*
4. *If you are using diesel, natural gas, or gasoline, you may skip this entry. Heat content units: BTU/gallon for liquid fuels, BTU/SCF for gaseous fuels. Sulfur content* units: weight % for liquid fuels, ppmv for gaseous fuels. (ppmv = parts per million by volume)
5. *Emission factors may be reported as gram/brakehp-hr, or as lb per gallon, or as lb per therm, or as lb per SCF.*
6. *See the Control Efficiency/Emission Factor Basis Code table under Section 3 on page 1 of this form.*
7. *Place a check in this column if the emission factor applies to emissions after abatement by an add-on abatement device.*

**7. CERTIFICATION** I hereby certify that all information contained herein is true and correct. *(Please sign and date this form)*

| GREG BOSSCALWEN | MANAGER | [signature] | 12/17/07 |
|---|---|---|---|
| Name of person certifying (print) | Title of person certifying | Signature of person certifying | Date |

Approved By: _____ Date: _____ Entered By: _____ Date: _____
(District Use Only)

| California Environmental Protection Agency AIR RESOURCES BOARD | DEERE POWER SYSTEMS GROUP OF DEERE & COMPANY | EXECUTIVE ORDER U-R-004-0264 New Off-Road Compression-Ignition Engines |
|---|---|---|

Pursuant to the authority vested in the Air Resources Board by Sections 43013, 43018, 43101, 43102, 43104 and 43105 of the Health and Safety Code; and

Pursuant to the authority vested in the undersigned by Sections 39515 and 39516 of the Health and Safety Code and Executive Order G-02-003;

**IT IS ORDERED AND RESOLVED:** That the following compression-ignition engines and emission control systems produced by the manufacturer are certified as described below for use in off-road equipment. Production engines shall be in all material respects the same as those for which certification is granted.

| MODEL YEAR | ENGINE FAMILY | DISPLACEMENT (liters) | FUEL TYPE | USEFUL LIFE (hours) |
|---|---|---|---|---|
| 2006 | 6JDXL08.1037 | 8.1 | Diesel | 8000 |

| SPECIAL FEATURES & EMISSION CONTROL SYSTEMS | TYPICAL EQUIPMENT APPLICATION |
|---|---|
| Direct Diesel Injection, Turbocharger, Charge Air Cooler, Electronic Control Module, Smoke Puff Limiter | Loaders, Tractor, Pump, Compressor, Generator Set, Other Industrial Equipment |

The engine models and codes are attached.

The following are the exhaust certification standards (STD), or family emission limit(s) (FEL) as applicable, and certification levels (CERT) for hydrocarbon (HC), oxides of nitrogen (NOx), or non-methane hydrocarbon plus oxides of nitrogen (NMHC+NOx), carbon monoxide (CO), and particulate matter (PM) in grams per kilowatt-hour (g/kW-hr), and the opacity-of-smoke certification standards and certification levels in percent (%) during acceleration (Accel), lugging (Lug), and the peak value from either mode (Peak) for this engine family (Title 13, California Code of Regulations, (13 CCR) Section 2423):

| RATED POWER CLASS | EMISSION STANDARD CATEGORY | | EXHAUST (g/kW-hr) | | | | | OPACITY (%) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | HC | NOx | NMHC+NOx | CO | PM | ACCEL | LUG | PEAK |
| 130 ≤ kW < 225 | Tier 3 | STD | N/A | N/A | 4.0 | 3.5 | 0.20 | 20 | 15 | 50 |
| 225 ≤ kW < 450 | Tier 3 | STD | N/A | N/A | 4.0 | 3.5 | 0.20 | 20 | 15 | 50 |
| | | FEL | - | - | 6.3 | - | - | - | - | - |
| | | CERT | - | - | 6.1 | 0.8 | 0.15 | 10 | 3 | 18 |

**BE IT FURTHER RESOLVED:** That the family emission limit(s) (FEL) is an emission level declared by the manufacturer for use in any averaging, banking and trading program and in lieu of an emission standard for certification. It serves as the applicable emission standard for determining compliance of any engine within this engine family under 13 CCR Sections 2423 and 2427.

**BE IT FURTHER RESOLVED:** That for the listed engine models, the manufacturer has submitted the information and materials to demonstrate certification compliance with 13 CCR Section 2424 (emission control labels), and 13 CCR Sections 2425 and 2426 (emission control system warranty).

Engines certified under this Executive Order must conform to all applicable California emission regulations.

**This Executive Order is only granted to the engine family and model-year listed above. Engines in this family that are produced for any other model-year are not covered by this Executive Order.**

Executed at El Monte, California on this 21st day of December 2005.

Raphael Susnowitz

for Allen Lyons, Chief
Mobile Source Operations Division

# Engine Model Summary Form

Manufacturer: **John Deere Power Systems of Deere and**

Engine category: **Nonroad CI**

EPA Engine Family: **6JDXL08.1037**

. amily Name: **450HF**

Process Code: **New Submission**

Attachment
U-R-004-0264

| 1.Engine Code | 2.Engine Model | 3.BHP@RPM (SAE Gross) | 4.Fuel Rate: mm/stroke @ peak HP (for diesel only) | 5.Fuel Rate: (lbs/hr) @ peak HP (for diesels only) | 6.Torque @ RPM (SEA Gross) | 7.Fuel Rate: mm/stroke@peak torque | 8.Fuel Rate: (lbs/hr)@peak torque | 9.Emission Control Device Per SAE J1930 |
|---|---|---|---|---|---|---|---|---|
| 6081HRW30 | 6081H | 285.64@2100 | 136.50@2100 | 98.70@2100 | 1000.00@1400 | 188.6@1400 | 89.05@1400 | EM EC SPL, EAC, TC |
| 6081HZ016 | 6081H | 303.08@2100 | 120.30@2100 | 102.52@2100 | 976.41@1500 | 159.5@1500 | 95.24@1500 | EM EC SPL |
| 6081HDW08 | 6081H | 199.28@2200 | 102.50@2200 | 76.13@2200 | 781.72@1500 | 151.5@1500 | 76.66@1500 | EM EC SPL |
| 6081HH019 | 6081H | 300.39@2200 | 137.10@2200 | 101.72@2200 | 840.71@1600 | 165.3@1600 | 89.22@1600 | EM EC SPL |
| 6081HT006A | 6081H | 199.15@2100 | 99.60@2100 | 70.55@2100 | 672.57@1500 | 132@1500 | 66.80@1500 | EM EC SPL |
| 6081HT006B | 6081H | 217.25@2100 | 107.80@2100 | 76.42@2100 | 733.78@1500 | 145.3@1500 | 73.42@1500 | EM EC SPL |
| 6081HT008 | 6081H | 261.50@2000 | 138.40@2000 | 93.30@2000 | 998.53@1500 | 196@1500 | 99.17@1500 | EM EC SPL |
| 6081HF070A | 6081H | 335.26@2200 | 160.00@2200 | 116.85@2200 | 1126.85@1400 | 226@1400 | 108.03@1400 | EM EC SPL |
| 6081HH027 | 6081H | 383.54@2200 | 181.20@2200 | 134.42@2200 | 1087.09@1600 | 219@1600 | 118.17@1600 | EM EC SPL |
| 6081HH026 | 6081H | 347.33@2200 | 162.70@2200 | 120.71@2200 | 974.93@1600 | 195.7@1600 | 105.63@1600 | EM EC SPL |

Data Form A
ABATEMENT DEVICE

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

*for office use only*

**Abatement Device**: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143 (If unknown, leave blank)
2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 11
3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr
4. Abatement Device Code (See table*) 66 Date of Initial Operation 8/29/08
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

   **S-** 41 **S-** 42 **S-** **S-** **S-**
   **S-** **A-** 12 **A-** **A-** **A-** **A-** **A-**

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

| | Pollutant | Weight Percent Reduction (at typical operation) | Basis Codes *(See Table**)* |
|---|---|---|---|
| 7. | Particulate | 0 | |
| 8. | Organics | 0 | |
| 9. | Nitrogen Oxides (as $NO_2$) | as necessary to achieve 2.0 ppm outlet | 3 |
| 10. | Sulfur Dioxide | 0 | |
| 11. | Carbon Monoxide | 0 | |
| 12. | Other: | | |
| 13. | Other: | | |

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

    **S-** **A-** **A-** **A-** **P-** 11 **P-**

Person completing this form: Nancy Matthews Date: 11/27/07

Data Form A
ABATEMENT DEVICE

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

*for office use only*

**Abatement Device**: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143 (If unknown, leave blank)
2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 12
3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr
4. Abatement Device Code (See table*) 72 Date of Initial Operation 8/29/08
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

   S- 41 S- 42 S- S- S- S-
   A- A- A- A- A- A-

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

| | Pollutant | Weight Percent Reduction (at typical operation) | Basis Codes *(See Table**)* |
|---|---|---|---|
| 7. | Particulate | 0 | |
| 8. | Organics | as necessary to achieve 2 ppm outlet | 3 |
| 9. | Nitrogen Oxides (as $NO_2$) | 0 | |
| 10. | Sulfur Dioxide | 0 | |
| 11. | Carbon Monoxide | as necessary to achieve 4 ppm outlet | 3 |
| 12. | Other: | | |
| 13. | Other: | | |

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

   S- A- 11 A- A- P- 11 P-

Person completing this form: Nancy Matthews Date: 11/27/07

Data Form A
ABATEMENT DEVICE

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

*for office use only*

**Abatement Device**: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143 (If unknown, leave blank)
2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 13
3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr
4. Abatement Device Code (See table*) 66 Date of Initial Operation 8/29/08
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

   **S-** 43 **S-** 44 **S-** **S-** **S-** **S-**
   **A-** 14 **A-** **A-** **A-** **A-** **A-**

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

| | Pollutant | Weight Percent Reduction (at typical operation) | Basis Codes *(See Table**)* |
|---|---|---|---|
| 7. | Particulate | 0 | |
| 8. | Organics | 0 | |
| 9. | Nitrogen Oxides (as $NO_2$) | as necessary to achieve 2.0 ppm outlet | 3 |
| 10. | Sulfur Dioxide | 0 | |
| 11. | Carbon Monoxide | 0 | |
| 12. | Other: | | |
| 13. | Other: | | |

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

    **S-** **A-** **A-** **A-** **A-** **P-** 12 **P-**

Person completing this form: Nancy Matthews Date: 11/27/07

*P:www\FormA (revised: 7/99)*

**Data Form A**
**ABATEMENT DEVICE**

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

*for office use only*

**Abatement Device**: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143 (If unknown, leave blank)
2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 14
3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr
4. Abatement Device Code (See table*) 72 Date of Initial Operation 8/29/08
5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

   **S-** 43 **S-** 44 **S-** **S-** **S-**
   **S-** **A-** **A-** **A-** **A-** **A-**

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

| | Pollutant | Weight Percent Reduction (at typical operation) | Basis Codes *(See Table**)* |
|---|---|---|---|
| 7. | Particulate | 0 | |
| 8. | Organics | as necessary to achieve 2 ppm outlet | 3 |
| 9. | Nitrogen Oxides (as $NO_2$) | 0 | |
| 10. | Sulfur Dioxide | 0 | |
| 11. | Carbon Monoxide | as necessary to achieve 4 ppm outlet | 3 |
| 12. | Other: | | |
| 13. | Other: | | |

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.
15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

    **S-** **A-** 13 **A-** **A-** **P-** 12 **P-**

Person completing this form: Nancy Matthews Date: 11/27/07

Form HRSA

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
WEBSITE: WWW.BAAQMD.GOV

## Health Risk Screening Analysis

**IMPORTANT:** For any permit application that requires a Health Risk Screening Analysis, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Gateway Generating Station Plant No.: 18143

Source Description: natural gas-fired combustion turbine with HRSG

Source No.: S- 41/S-42 (if known) Emission Point No.: P- 11 (if known)

### SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO
   ***(If YES continue at #2, If NO, skip to Section B)***
2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☐ alone OR ☑ on roof
   *Important: If stack is on a roof, provide building dimensions on line B1 in* Section C.
3. What is the height of the stack outlet above ground level? 195 feet OR _____ meters?
4. What is the inside diameter of the stack outlet? _____ inches OR 16.76 feet OR _____ meters
5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical
6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 936640 cfm (cubic feet/min) OR _____ meters$^3$/second
8. What is the typical temperature of the exhaust gas? 180 degrees Fahrenheit OR _____ degrees Celsius
   ***(Skip Section B and Go on to Section C)***

### SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

_____

_____

***(Go on to Section C)***

## SECTION C *(Building Dimensions)*

*Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings.* Check one for units: ☐ feet OR ☐ meters

| B# | Building name or description | Height | Width | Length | Distance To Source | Direction To Source |
|---|---|---|---|---|---|---|
| B1 | Building with source: | | | | n/a | n/a |
| B2 | please see application support | | | | | |
| B3 | document for building details | | | | | |
| B4 | | | | | | |
| B5 | | | | | | |
| B6 | | | | | | |
| B7 | | | | | | |
| B8 | | | | | | |
| B9 | | | | | | |

***NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).***

_____

_____

_____

_____

***(Go on to Section D)***

## SECTION D *(Receptor Locations)*

***NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.***

1. Indicate the area where the source is located (check one):
   - ☐ zoned for residential use
   - ☐ zoned for mixed residential and commercial/industrial use
   - ☑ zoned for commercial and/or industrial use
   - ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 80 feet OR _____ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3900 feet OR _____ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other _____
5. Distance from source (stack or building) to property line of nearest nonresidential site = 250 feet OR _____ meters
6. Distance from source to property line of nearest school* (or school site) = _____ feet OR ☑ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   None.

*K-12 and more than twelve children only

*HRSA-101205*

Form HRSA

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
WEBSITE: WWW.BAAQMD.GOV

## Health Risk Screening Analysis

**IMPORTANT:** For any permit application that requires a Health Risk Screening Analysis, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Gateway Generating Station Plant No.: 18143

Source Description: natural gas-fired combustion turbine with HRSG

Source No.: S- 43/S-44 (if known) Emission Point No.: P- 12 (if known)

### SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO
   ***(If YES continue at #2, If NO, skip to Section B)***
2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☐ alone OR ☑ on roof
   *Important: If stack is on a roof, provide building dimensions on line B1 in* Section C.
3. What is the height of the stack outlet above ground level? 195 feet OR _____ meters?
4. What is the inside diameter of the stack outlet? _____ inches OR 16.76 feet OR _____ meters
5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical
6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 936640 cfm (cubic feet/min) OR _____ meters$^3$/second
8. What is the typical temperature of the exhaust gas? 180 degrees Fahrenheit OR _____ degrees Celsius
   ***(Skip Section B and Go on to Section C)***

### SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

_____

_____

***(Go on to Section C)***

## SECTION C *(Building Dimensions)*

*Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings.* Check one for units: ☐ feet OR ☐ meters

| B# | Building name or description | Height | Width | Length | Distance To Source | Direction To Source |
|---|---|---|---|---|---|---|
| B1 | Building with source: | | | | n/a | n/a |
| B2 | please see application support | | | | | |
| B3 | document for building details | | | | | |
| B4 | | | | | | |
| B5 | | | | | | |
| B6 | | | | | | |
| B7 | | | | | | |
| B8 | | | | | | |
| B9 | | | | | | |

***NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).***

***(Go on to Section D)***

## SECTION D *(Receptor Locations)*

***NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.***

1. Indicate the area where the source is located (check one):
   ☐ zoned for residential use ☐ zoned for mixed residential and commercial/industrial use
   ☑ zoned for commercial and/or industrial use ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 80 feet OR _____ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3700 feet OR _____ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other _____
5. Distance from source (stack or building) to property line of nearest nonresidential site = 500 feet OR _____ meters
6. Distance from source to property line of nearest school* (or school site) = _____ feet OR ☑ Greater than 1,000 feet
   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]
   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:
   None.

*K-12 and more than twelve children only

*HRSA-101205*

Form HRSA

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
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## Health Risk Screening Analysis

**IMPORTANT:** For any permit application that requires a Health Risk Screening Analysis, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Gateway Generating Station Plant No.: 18143

Source Description: natural gas-fired dewpoint heater

Source No.: S- 45 (if known) Emission Point No.: P- 13 (if known)

### SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO
   ***(If YES continue at #2, If NO, skip to Section B)***
2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☑ alone OR ☐ on roof
   *Important: If stack is on a roof, provide building dimensions on line B1 in* Section C.
3. What is the height of the stack outlet above ground level? 15 feet OR _____ meters?
4. What is the inside diameter of the stack outlet? _____ inches OR 0.67 feet OR _____ meters
5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical
6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 1964 cfm (cubic feet/min) OR _____ meters$^3$/second
8. What is the typical temperature of the exhaust gas? 300 degrees Fahrenheit OR _____ degrees Celsius
   ***(Skip Section B and Go on to Section C)***

### SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

_____

_____

***(Go on to Section C)***

## SECTION C *(Building Dimensions)*

*Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings.* Check one for units: ☐ feet OR ☐ meters

| B# | Building name or description | Height | Width | Length | Distance To Source | Direction To Source |
|---|---|---|---|---|---|---|
| B1 | Building with source: | | | | n/a | n/a |
| B2 | please see application support | | | | | |
| B3 | document for building details | | | | | |
| B4 | | | | | | |
| B5 | | | | | | |
| B6 | | | | | | |
| B7 | | | | | | |
| B8 | | | | | | |
| B9 | | | | | | |

***NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).***

_____

_____

_____

_____

***(Go on to Section D)***

## SECTION D *(Receptor Locations)*

***NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.***

1. Indicate the area where the source is located (check one):
   - ☐ zoned for residential use
   - ☐ zoned for mixed residential and commercial/industrial use
   - ☑ zoned for commercial and/or industrial use
   - ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 80 feet OR _____ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3600 feet OR _____ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other _____
5. Distance from source (stack or building) to property line of nearest nonresidential site = 700 feet OR _____ meters
6. Distance from source to property line of nearest school* (or school site) = _____ feet OR ☑ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   None.

*K-12 and more than twelve children only

Form HRSA

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939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
WEBSITE: WWW.BAAQMD.GOV

## Health Risk Screening Analysis

**IMPORTANT:** For any permit application that requires a Health Risk Screening Analysis, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Gateway Generating Station Plant No.: 18143

Source Description: Diesel fire pump engine

Source No.: S- 48 (if known) Emission Point No.: P- 18 (if known)

### SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO
   ***(If YES continue at #2, If NO, skip to Section B)***
2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☐ alone OR ☑ on roof
   *Important: If stack is on a roof, provide building dimensions on line B1 in* Section C.
3. What is the height of the stack outlet above ground level? 10.67 feet OR _____ meters?
4. What is the inside diameter of the stack outlet? _____ inches OR 0.5 feet OR _____ meters
5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical
6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 1740 cfm (cubic feet/min) OR _____ meters$^3$/second
8. What is the typical temperature of the exhaust gas? 770 degrees Fahrenheit OR _____ degrees Celsius
   ***(Skip Section B and Go on to Section C)***

### SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

_____

_____

***(Go on to Section C)***

## SECTION C *(Building Dimensions)*

*Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings.* Check one for units: ☐ feet OR ☐ meters

| B# | Building name or description | Height | Width | Length | Distance To Source | Direction To Source |
|---|---|---|---|---|---|---|
| B1 | Building with source: | | | | n/a | n/a |
| B2 | please see application support | | | | | |
| B3 | document for building details | | | | | |
| B4 | | | | | | |
| B5 | | | | | | |
| B6 | | | | | | |
| B7 | | | | | | |
| B8 | | | | | | |
| B9 | | | | | | |

***NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).***

_____

_____

_____

_____

***(Go on to Section D)***

## SECTION D *(Receptor Locations)*

***NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.***

1. Indicate the area where the source is located (check one):
   - ☐ zoned for residential use
   - ☐ zoned for mixed residential and commercial/industrial use
   - ☑ zoned for commercial and/or industrial use
   - ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 120 feet OR _____ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3600 feet OR _____ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other _____

   _____
5. Distance from source (stack or building) to property line of nearest nonresidential site = 1100 feet OR _____ meters
6. Distance from source to property line of nearest school* (or school site) = _____ feet OR ☑ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   None.

*K-12 and more than twelve children only

# EXHIBIT G

**Pacific Gas and Electric Company®**

*Mailing Address:*
Pacific Gas & Electric Company
Gateway Generating Station
3225 Wilbur Ave.
Antioch, CA 94509
(925) 522-7801

February 13, 2009

Brian Bateman
Director of Engineering
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Application for Modifications to the Authority to Construct
Gateway Generating Station—Plant No. 18143, Application No. 17182

Dear Mr. Bateman:

PG&E hereby withdraws Application No. 17182, the application for modifications to the Authority to Construct for the Gateway Generating Station (GGS), which was filed with the District in December 2007. As we have discussed with you, the principal reason for requesting the permit modifications was because we believed that the original conditions governing commissioning and startups were overly stringent and could not be complied with. In our application we had requested changes to these conditions that would have increased some emissions limits and extended some time periods related to commissioning and startups. However, GGS has completed commissioning in compliance with the existing conditions, so no revisions are needed for commissioning-related conditions. Further, GGS has completed several warm and hot startups and two complete cold startups. Based on the data collected during these startups, we now believe we can comply with the existing startup conditions. As a result, we no longer believe the amendments originally requested in our December 2007 application are necessary.

We appreciate the assistance you and your staff have provided during the permit review. If you have any questions regarding this request to withdraw the application, please do not hesitate to call me or Gary Rubenstein of Sierra Research at (916) 444-6666.

Sincerely,

Thomas Allen
Project Manager

cc: Brian Lusher, BAAQMD Permit Services
Andrea Grenier, Grenier & Associates
Scott Galati, Galati Blek
Gary Rubenstein, Sierra Research

# EXHIBIT H

# Preliminary
# Determination of Compliance

## Contra Costa Power Plant
## Unit 8 Project

Bay Area Air Quality Management District
Application 1000

October 23, 2000

Dick Wocasek, P.E.
Air Quality Engineer

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# I Introduction

This is the Preliminary Determination of Compliance (PDOC) for the Unit 8 Project at the existing Contra Costa Power Plant (CCPP), a 530-MW, natural-gas fired, combined cycle merchant power plant proposed by Southern Energy California. The existing power plant is located about 1-mile northeast of the city of Antioch on Wilbur Avenue near State Route (SR) 4, SR 160 and the Antioch Bridge. The new unit will include two natural gas fired General Electric Frame 7FA combustion turbine generators (CTGs), one steam turbine generator and associated equipment, two supplementally fired heat recovery steam generators (HRSGs) and a wet cooling tower.

## A. Background

Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Preliminary Determination of Compliance (PDOC) document for the CCPP Unit 8. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #1000. The PDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

Pursuant to Regulation 2, Rule 3, Section 404, this PDOC is subject to the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

## B. Project Description

### 1. Process Equipment

The applicant is proposing a combined-cycle cogeneration facility with a maximum electrical output of 530 MW. The CCPP Unit 8 will consist of the following new permitted equipment:

S-41 Combustion Gas Turbine #1, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-42 Heat Recovery Steam Generator #1, 395 MM Btu per hour, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-43 Combustion Gas Turbine #2, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-$NO_x$ Combustors, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-44 Heat Recovery Steam Generator #2, 395 MM Btu per hour, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-45 Gas-Fired Fuel Preheater, 12 MM Btu per hour.

S-46 10-Cell Wet Cooling Tower, 125,000 gallons per minute

As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 175 MW and the steam produced by both heat recovery steam generators (HRSGs) will feed to a single steam turbine generator with a nominal electrical output of 192 MW.

## 2. Equipment Operating Scenarios

*Turbines and Heat Recovery Steam Generators*

As a merchant power plant, market circumstances and demand will dictate the exact operation of the new gas turbine/HRSG power trains. However, the following general operating modes are projected to occur:

*Base Load:* Maximum continuous output with duct firing and power augmentation steam injection during high ambient temperature conditions

*Load Following:* Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

*Partial Shutdown:* Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during period of low overall demand such as late evening and early morning hours

*Full Shutdown:* May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

*HRSG Duct Burner Firing with Steam Injection Power Augmentation:*

Under peak demand situations and high ambient temperatures, steam may be injected into the gas turbine combustors to lower the flame temperature and allow increased fuel use rate, which results in increased mass flow through the gas turbine thereby increasing maximum electrical output.

The following projected operating scenario was utilized to estimate maximum annual air pollutant emissions from the new gas turbines and HRSGs.

- 4304 hours of baseload (100% load) operation per year for each gas turbine @ 60°F
- 4313 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 83 gas turbine hot start-ups per year (90 min. each)
- 28 gas turbine cold start-ups per year (256 min. each)
- 111 gas turbine shutdowns per year (23 min. each)

### 3. Air Pollution Control Strategies and Equipment

The proposed CCPP Unit 8 includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides ($NO_x$), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide ($SO_2$), and particulate matter of less than 10 microns in diameter ($PM_{10}$).

#### a. Selective Catalytic Reduction with Ammonia Injection for the Control of $NO_x$

The gas turbines and HRSG duct burners each trigger BACT for $NO_x$ emissions. The gas turbines will be equipped with dry low-$NO_x$ (DLN) combustors, which are designed to minimize $NO_x$ emissions. The HRSGs will be equipped with low-$NO_x$ duct burners, which are designed to minimize $NO_x$ emissions. In addition, the combined $NO_x$ emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level $NO_x$ emission limit of 2.5 ppmvd @ 15 % $O_2$ (one hour average).

#### b. Dry Low-$NO_x$ (DLN) Combustors and Oxidation Catalyst to Minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-$NO_x$ combustors, which are also designed to minimize CO emissions. The HRSGs will be equipped with a CO catalyst designed to catalytically oxidize the CO and POC produced from firing natural gas in the CT and duct burner. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level CO emission limit of 6.0 ppmvd @ 15 % $O_2$ and a POC level of 2.0 ppmvd @ 15 % $O_2$.

#### c. Dry Low-$NO_x$ (DLN) Combustors and the CO catalyst to minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-$NO_x$ combustors, which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with a CO catalyst to minimize CO and POC emissions.

#### d. Exclusive Use of Clean-burning Natural gas to Minimize $SO_2$ and $PM_{10}$ Emissions

The gas turbines and HRSG duct burners will utilize exclusively natural gas as a fuel to minimize $SO_2$ and $PM_{10}$ emissions. Because the emission rate of $SO_2$ depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics; the use of natural gas will result in the lowest possible emission of $SO_2$. $PM_{10}$ emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

# II Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

**Table 1** is a summary of the daily maximum regulated air pollutant emissions for the gas turbines, heat recovery steam generators (HRSGs) and cooling tower. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that will result in POC, NPOC, $NO_x$, $SO_2$, $PM_{10}$, or CO emissions in excess of 10 pounds per highest day per pollutant are subject to the BACT requirement for that pollutant.

## Table 1 Maximum Daily Regulated Air Pollutant Emissions for Baseload Operation of Proposed Sources[a] (lb./day)

| Pollutant | Source | | | |
|---|---|---|---|---|
| | S-41 CTG & S-42 HRSG[a] | S-43 CTG & S-44 HRSG[a] | S-45 Fuel Preheater[b] | S-46 Cooling Tower |
| Nitrogen Oxides (as $NO_2$) | 997 | 997 | 2.6 | |
| Carbon Monoxide | 1801 | 1801 | 0.9 | |
| Precursor Organic Compounds | 234 | 234 | 1.1 | |
| Particulate Matter ($PM_{10}$) | 312 | 312 | 0.5 | 43 |
| Sulfur Dioxide | 148 | 148 | 0.2 | |

[a]Based upon one cold start, one hot start, 16 hours of CTG/HRSG baseload operation with HRSG firing and steam injection power augmentation and 2.2 hours of CTG/HRSG baseload operation in a 24-hour period.

[b] The Fuel Preheater is operated only during starts.

**Table 2** is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions

shown are based upon a worst-case ammonia emission concentration of 10 ppmvd @ 15% $O_2$ due to ammonia slip from the A-11 and A-13 SCR Systems.

## Table 2
## Maximum Facility Toxic Air Contaminant (TAC) Emissions

| Toxic Air Contaminant | Pounds/year | Risk Screening Trigger Level[a] (lb./yr-source) |
|---|---|---|
| S-41, S-42, S-43, and S-44 Combined | | |
| Acetaldehyde[b] | 2558 | 72 |
| Acrolein | 884 | 3.9 |
| Ammonia[c] | 518,242 | 19,300 |
| Benzene[b] | 506 | 6.7 |
| 1,3-Butadiene[b] | 4 | 1.1 |
| Ethylbenzene | 670 | 193,000 |
| Formaldehyde[b] | 4102 | 33 |
| Hexane | 9630 | 83,000 |
| Naphthalene | 62 | 270 |
| PAHs[b] | 38 | 0.043 |
| Propylene | 39,214 | none specified |
| Propylene Oxide[b] | 1780 | 52 |
| Toluene | 2706 | 38,600 |
| Xylenes | 1078 | 57,900 |
| Cooling Tower Emissions, S-46[d] | | |
| Arsenic[b] | 0.016 | 0.024 |
| Beryllium | 0.041 | 0.014 |
| Cadmium[b] | 0.00010 | 0.046 |
| Chromium VI[b] | 0.018 | 0.0014 |
| Copper | 0.024 | 463 |
| Lead[b] | 0.003 | 16 |
| Manganese | 0.15 | 77 |
| Mercury | 0.0007 | 57.9 |
| Nickel | 0.023 | 73 |
| Selenium | 0.002 | 97 |
| Zinc | 0.017 | 6,760 |
| Fuel Pre-Heater, S-45 | | |
| Acetaldehyde[b] | 0.025 | 72 |
| Arsenic | 0.00056 | 0.024 |
| Benzene | 0.025 | 6.7 |
| Beryllium | 3.37E-5 | 0.014 |
| Cadmium[b] | 0.0031 | 0.046 |
| Chromium VI[b] | 0.040 | 0.0014 |
| Copper | 0.0024 | 463 |

| Toxic Air Contaminant | Pounds/year | Risk Screening Trigger Level[a] (lb./yr-source) |
|---|---|---|
| Formaldehyde | 0.624 | 33 |
| Hexane | 5.08 | 83,000 |
| Manganese | 0.0011 | 77 |
| Mercury | 0.0007 | 57.9 |
| Naphthalene | 0.0017 | 270 |
| Nickel | 0.006 | 73 |
| PAHs, Total | 0.00005 | 0.043 |
| Selenium | 0.00005 | 97 |
| Toluene | 0.0097 | 38,600 |
| Zinc | 0.082 | 6,760 |

[a]pursuant to BAAQMD Toxic Risk Management Policy

[b]carcinogenic compound

[c]based upon the worst-case ammonia slip of 10 ppmvd @ 15% $O_2$ from the A-11 and A-13 SCR systems with ammonia injection

[d]based on San Joaquin River water analysis and cooling tower drift rate.

**Table 3** is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of the trigger levels shown must perform modeling to assess the net air quality impact of that pollutant.

## Table 3
## Maximum Annual Facility Regulated Air Pollutant Emissions Increase

| Pollutant | Cumulative Increase Emissions[a,b] (tons/year) | PSD Trigger[c] (tons/year) |
|---|---|---|
| Nitrogen Oxides (as $NO_2$) | 174.3 | 40 |
| Carbon Monoxide | 259.1 | 100 |
| Precursor Organic Compounds | 46.6 | N/A |
| Particulate Matter ($PM_{10}$) | 112.2 | 15 |
| Sulfur Dioxide | 48.5 | 40 |

[a]Includes emissions from two gas turbines, heat recovery steam generators, natural-gas-fired preheater and cooling tower.

[b]Emissions include 28 cold startups, 83 hot startups, and 111 shutdowns, and 8,626 hours at 100% duct burner capacity with the balance of the time at 100% load at 60F.

[c]For a new major facility.

# III Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed CCPP Unit 8 will comply with those requirements.

## A. Regulation 2, Rule 2; New Source Review

The primary requirements of New Source Review that apply to the proposed CCPP Unit#8 facility are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2-302; "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR", and Section 2-2-404, "PSD Air Quality Analysis".

### 1. Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and must have been demonstrated to be effective and reliable on a full-scale unit and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The following section includes BACT determinations by pollutant for the permitted sources of the proposed CCPP Unit 8. Because each Gas Turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

**Nitrogen Oxides ($NO_x$)**

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for $NO_x$ as 2.5 ppmvd @ 15% $O_2$ with an averaging period of one hour. This BACT determination was based upon the use of SCR and Low $NO_x$ combustors or a SCONOX System. This determination is based on recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595), Delta Energy Center (Application # 19414) and Metcalf Energy Center (Application # 27215). The EPA has accepted this BACT determination as Federal LAER and further established a $NO_x$ concentration of 2.0 ppmvd @ 15% $O_2$ averaged over three hours as equivalent to 2.5 ppmvd @ 15% $O_2$, averaged over one hour. CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a $NO_x$ emission concentration limit of 2.5 ppmvd $NO_x$ @ 15% $O_2$, averaged over one hour, during all operating modes except gas turbine start-ups and shutdowns. Compliance with this emission limitation will be achieved through the use of a selective catalytic reduction (SCR) system with ammonia injection and will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. This unit will be restricted to 16 hours of operation per day, which results in a $NO_x$ emission of 7.2 lbs./day. BACT is therefore not required.

**Carbon Monoxide (CO)**

BACT for CO will be analyzed within the context of three distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing. The third mode includes gas turbine firing at maximum load with HRSG duct burner firing and steam injection power augmentation at the gas turbine combustors. Steam injection power augmentation lowers the combustor flame temperature thereby allowing an increased fuel use rate, which in turn

increases gas turbine peak generating capacity during periods of high ambient temperature. However, by lowering the combustor flame temperature steam injection can increase CO production.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for CO as 6 ppmvd, @ 15% $O_2$ with an averaging period of one hour. This BACT determination was based upon the use of CO Catalyst and Dry Low $NO_x$ combustors. This determination is based on recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595) and Metcalf Energy Center (Application # 27215). CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

  The CCPP Unit 8 has agreed to a CO emission limit of 6 ppmvd @ 15% $O_2$ that will apply to all gas turbine/HRSG operating modes except for gas turbine start-up and shutdown. As is the case for Los Medanos Energy Center, this limit will apply to the firing of the turbine alone, turbine operation with HRSG duct burner firing, and steam injection power augmentation mode. The CCPP Unit 8 intends to comply with this BACT specification through the use of dry low-$NO_x$ duct burners, which minimize incomplete combustion, and by the use of a CO oxidation catalyst.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. This unit will be restricted to 16 hours of operation per day, which results in a CO emission of 2.4 lbs./day. BACT is therefore not required.

**Precursor Organic Compounds (POCs)**

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for POC as 2 ppmvd, @ 15% $O_2$ with an averaging period of one hour. This BACT determination was based upon the use of an Oxidation Catalyst or Dry Low $NO_x$ combustors. This determination is based on recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595) and Metcalf Energy Center (Application # 27215). CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve POC emissions no greater than 1.1 lbs./day so a BACT determination is not required for this unit.

**Sulfur Dioxide ($SO_2$)**

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6 specifies BACT for $SO_2$ for gas turbines with a heat input rating $\geq$ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal $SO_2$ emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 1 grain/scf. This corresponds to an $SO_2$ emission factor of 0.0028 lb./MM Btu. The natural gas sulfur content specification of 1 grain per 100 scf is deemed BACT for $SO_2$.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve $SO_2$ emissions no greater than 0.2 lbs./day based on 6 hours of operation. A BACT determination is therefore not required.

**Particulate Matter ($PM_{10}$)**

- Combustion Gas Turbines

  District BACT Guideline 89.1.6 specifies BACT for $PM_{10}$ for gas turbines with a heat input rating $\geq$ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal $PM_{10}$ emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 1 grain/scf. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal direct $PM_{10}$ emissions and minimal formation of secondary $PM_{10}$ such as sulfates.

- Cooling Tower

  Southern Energy is proposing a cooling tower with a drift rate of 0.0005 %. Based on a recent BACT determination by the San Joaquin Valley Unified APCD (Guideline 8.3.10). The District considers BACT for the cooling towers to be a drift rate of 0.0006 % which will be published in BAAQMD BACT Guideline 181.1. The proposed drift rate is therefore acceptable.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve $PM_{10}$ emissions no greater than 0.5 lbs./hour based on 6 hours of operation and therefore a BACT determination is not required.

## 2. Emission Offsets

### General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and $NO_x$ emission increases from permitted sources at facilities, which will emit 15 tons per year or more on a pollutant-specific basis. Because the CCPP facility will emit more than 50 tons per year of $NO_x$, offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Because CCPP will emit more than 50 tons/year of POC, offsets must be provided, by the applicant, at a ratio of 1.15 to 1.0.

Pursuant to Regulation 2-2-303, emission offsets shall be provided (at a ratio of 1.0:1.0) for $PM_{10}$ emission increases at facilities that will be permitted to emit more than 100 tons of $PM_{10}$ per year. These offsets will be required for the gas turbines, HRSGs and the cooling tower. Pursuant to Regulation 2-2-303.1, emission reduction credits of nitrogen oxides or sulfur dioxide may be used to offset $PM_{10}$ emission increases. The applicant is proposing to offset $PM_{10}$ at a ratio of 3 tons of sulfur dioxide for each ton of $PM_{10}$. This is the same ratio that that has been used for the nearby Delta Energy Center project. The APCO has determined that the same ratio is acceptable for this application.

It should be noted that in the case of POC and $NO_x$ offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset.

### Timing for Provision of Offsets

Pursuant to District Regulation 2-2-311, the applicant must "provide" the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct. Pursuant to District Regulation 2, Rule 3, "Power Plants," the Authority to Construct will be issued after the California Energy Commission issues the Certificate for the power plant. Historically, the BAAQMD has not required the applicant to provide the actual banking certificates to the District prior to the issuance of the Authority to Construct. Rather, the District has accepted the applicant's demonstration of control of valid offsets through enforceable contracts or options to purchase as equivalent to the "provision" of offsets as required by Regulation 2-2-311. The actual banking certificates must be surrendered to the District prior to the issuance of the Permit to Operate.

### Interpollutant Offset Ratios

Pursuant to District Regulation, 2-2-303.1, an applicant can provide $NO_x$ and/or $SO_2$ emission credits to offset $PM_{10}$ emission increases at ratios deemed appropriate by the APCO. Pursuant to current District policy, the default interpollutant trade-off ratios for Eastern Contra Costa County are 6 to 1 for $NO_x$ and 4 to 1 for $SO_2$. These ratios represent "conservative best-estimate values" from an interpollutant trade-off study conducted by Systems Applications International (SAI) for the Shell Refinery located in Martinez, California. More specifically, the analysis specifies a "best estimate" trade-off ratio for the Pittsburg area of 3 to 1 for $SO_2$ to $PM_{10}$. Because the

Contra Costa Unit #8 project will be located within 8 miles of the Pittsburg monitoring station the trade-off ratio of 3 tons of $SO_2$ for each ton of $PM_{10}$ will be used. Please see Appendix C, Attachment 1 for the District policy memorandum regarding this trade-off ratio.

The SAI analysis utilized three methods to estimate the amount of secondary $PM_{10}$ formation resulting from the emission of $NO_x$ and $SO_2$. The first method was based entirely upon the analysis of air quality data. The second method used a photochemical box model to compute the aerosol yield from a unit of $NO_x$ or $SO_2$ emissions. The third method used the photochemical model to simulate the effect of an incremental unit of precursor emissions on a typical atmosphere with variable mixing height. The inter-pollutant trade-off ratios generated by the SAI analysis only apply to facilities located in the eastern portion of Contra Costa County. Under current District policy, if an applicant wishes to utilize different (i.e. lower) interpollutant offset ratios, they must submit an analysis for review by the District Planning Division.

**Offset Requirements by Pollutant**

The applicable offset ratios and the quantity of offsets required are summarized in Appendix C, Table C-1.

POC Offsets

Because the combined emissions from the existing and proposed units at the CCPP facility will exceed 50 tons per year of Precursor Organic Compounds (POCs), the POC emission increases must be offset at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302.

$NO_x$ Offsets

Because the CCPP Unit 8 will emit greater than 50 tons per year of Nitrogen Oxides (as $NO_2$) from permitted sources, the applicant must provide emission reduction credits (ERCs) of $NO_x$ at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302.

$PM_{10}$ Offsets

With projected $PM_{10}$ emissions from permitted sources of greater than 100 tons per year, the CCPP Unit 8 triggers the $PM_{10}$ offset requirement of District Regulation 2-2-303. The applicant plans to offset the $PM_{10}$ with $SO_2$ credits at a ratio of 3:1.

$SO_2$ Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed $SO_2$ emission increases associated with this project since the facility $SO_2$ emissions will not exceed 100 tons per year. Regulation 2-2-303 does allow for the voluntary offsetting of $SO_2$ emission increases of less than 100 tons per year. The applicant has not opted to provide such emission offsets.

**Current Proposed Offset Package**

**Table 4** summarizes the current offset obligation of the CCPP Unit 8 and the quantity of valid emission reduction credits (ERCs) under the control of Southern Energy. The emission reduction credits presented in Table 4 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, "Emissions Banking", and were subsequently issued as a banking certificate by the BAAQMD.

As indicated, Southern Energy has secured sufficient valid emission reduction credits to offset the emission increases from the permitted sources proposed for the CCPP Unit 8.

## Table 4
## Emission Reduction Credits Identified by Southern Energy as of September 25, 2000 (ton/yr)

| | POC[a] | $NO_x$[b] | $PM_{10}$[c] |
|---|---|---|---|
| Valid Emission Reduction Credits | 53.6 | 200.5 | 112.2 |
| Permitted Source Emission Limits | 46.6 | 174.3 | 112.2 |
| Offsets Required per BAAQMD Calculations | 53.6[d] | 200.5[d] | 112.2[e] |

[a]From Banking Certificate # 693.

[b]From Banking Certificate # 693.

[c]$SO_2$ used at a ratio of 3:1. The following $SO_2$ Banking Certificates used:

#693 321.90 tons

#694 14.53 tons

#695 0.17 tons

**Total 336.60 tons** ($PM_{10}$ equivalent 112.2 tons)

[d]Reflects applicable offset ratio of 1.15:1.0 pursuant to Regulation 2-2-302

[e]Reflects applicable offset ratio of 1.0:1.0 pursuant to Regulation 2-2-302

These Banking Certificates originated from the following locations:

| Certificate | Company | Location | Original Issue Date |
|---|---|---|---|
| #693 | Gaylord Container | Antioch | 6/8/84 |
| #694 | P G & E | Martinez | 7/22/87 |
| #695 | Hudson ICS | San Leandro | 4/9/97 |

## 3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the CCPP Unit#8 project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the CCPP Unit#8 facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for $NO_2$, CO, and $PM_{10}$ or an exceedence of any applicable PSD increment. **Table 5** summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution form the proposed CCPP Unit#8.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation.

**Table 5**
**California and National Ambient Air Quality Standards and Ambient Air Quality Levels from the Proposed CCPP Unit#8 ($\mu g/m^3$)**

| Pollutant | Averaging Time | Maximum Background | Maximum Project impact | Maximum Project impact plus maximum background | California Standards | National Standards |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-hour | 164 | 225 | 389 | 470 | --- |

Please see Appendix E for a detailed discussion of the PSD air quality impact analysis.

## B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the CCPP Unit#8 project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the CCPP Unit#8 are summarized in Table 2. In accordance with the requirements of the BAAQMD Toxic Risk Management Policy (TRMP) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

## Table 6 Health Risk Assessment Results

| Source | Multi-pathway Carcinogenic Risk (risk in one million) | Non-carcinogenic Chronic Hazard Index | Non-carcinogenic Acute Hazard Index[a] |
|---|---|---|---|
| Gas Turbines, HRSGs, and Cooling Tower[b] | 0.67 | 0.04 | 0.2 |

[a]included for informational purposes only; BAAQMD TRMP does not require an assessment of acute (short-term; i.e. < 24 hour) health impacts

[b]numbers represent combined risk from all sources

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to the BAAQMD Risk Management Policy, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. The chronic hazard index attributed to the emission of non-carcinogenic air contaminants is considered to be not significant since it is less than 1.0. Therefore, the CCPP Unit#8 facility is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. Please see Appendix D for further detail.

## C. Other Applicable District Rules and Regulations

**Regulation 1, Section 301: Public Nuisance**

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis insures that the proposed facility will comply with this Regulation.

**Regulation 2, Rule 1, Sections 301 and 302:**
**Authority to Construct and Permit to Operate**

Pursuant to Regulation 2-1-301 and 2-1-302, the CCPP Unit 8 has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-41 & S-43 Gas Turbines, S-42 & S-44 Heat Recovery Steam Generators, S-45 Fuel Preheater and S-46 Cooling Tower.

**Regulation 2, Rule 3: Power Plants**

Pursuant to Regulation 2-3-403, this Preliminary Determination of Compliance (PDOC) serves as the APCO's preliminary decision that the proposed power plant will meet the requirements of

all applicable BAAQMD, state, and federal regulations. The PDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-304, the PDOC will be subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407.

**Regulation 2, Rule 6: Major Facility Review**

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the CCPP Unit#8 shall submit an application to the BAAQMD for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Regulation 2-6-212.1, the CCPP Unit#8 will become subject to Regulation 2, Rule 6 upon initial firing of any of the gas turbines (S-41 & S-43) or HRSGs (S-42 & S-44).

**Regulation 2, Rule 7: Acid Rain**

The CCPP Unit 8 gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), CCPP Unit#8 must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. Pursuant to 40 CFR Part 72.2, "commence operation" includes the start-up of the unit's combustion chamber.

**Regulation 6: Particulate Matter and Visible Emissions**

Through the use of dry low-$NO_x$ burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines and HRSG duct burners is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the simultaneous operation of each power train (CTG and HRSG Duct Burners) is 0.0022 gr./dscf @ 6% $O_2$. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 5666 mg/l and corresponding maximum $PM_{10}$ emission rate of 1.77 lb./hr, the proposed exempt 10-cell cooling tower is expected to comply with the requirements of Regulation 6.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. It is expected that the California Energy Commission will impose conditions on construction activities that will require the use of water and/or chemical dust suppressants to minimize $PM_{10}$ emissions and prevent visible particulate emissions.

**Regulation 7: Odorous Substances**

Regulation 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the two proposed CTG/HRSG power trains will each be limited by permit condition to 10 ppmvd @ 15% $O_2$, the facility is expected to comply with the requirements of Regulation 7.

**Regulation 8: Organic Compounds**

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at the CCPP Unit#8.

The use of solvents for cleaning and maintenance at the CCPP Unit#8 is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

**Regulation 9: Inorganic Gaseous Pollutants**

Regulation 9, Rule 1, Sulfur Dioxide

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level $SO_2$ concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits $SO_2$ emissions in excess of 300 ppmv (dry). With maximum projected $SO_2$ emissions of < 1 ppmv, the gas turbines and HRSG duct burners are not expected to contribute to noncompliance with ground level $SO_2$ concentrations and should easily comply with section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The proposed combustion gas turbines (each rated at 1,872 MM Btu/hr HHV) shall comply with the Regulation 9-3-303 $NO_x$ limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.5 ppmvd @ 15% $O_2$. The HRSG duct burners will also be limited to 2.5 ppmvd and therefor comply with this regulation.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed HRSGs are exempt from Regulation 9, Rule 7, per section 110.5 since they are used to recover sensible heat from the exhaust of the proposed combustion turbines.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the proposed combustion gas turbines and HRSGs will be limited by permit condition to $NO_x$ emissions of 2.5 ppmvd @ 15% $O_2$, they are expected to comply with the Regulation 9-9-301.3 $NO_x$ limitation of 9 ppmvd @ 15% $O_2$.

## D. CEQA

The CEQA requirements of regulation 2-1-426 are met because the California Energy Commission (CEC) has taken the lead agency roll on this project and are responsible for the EIR, which will fulfill the CEQA requirement. The Application for Certification that the applicant has submitted to the CEC serves as the EIR.

# IV Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb./hr and lb./MM Btu of natural gas fired) will ensure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and $NO_x$ limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. If the CO and $NO_2$ CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable gas content and the differing response times of the gas monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, $SO_2$, and $PM_{10}$ mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to as designed operation of each CTG/HRSG power train and the auxiliary boilers, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and oxidation catalysts fully operational. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 1 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedence of any short-term applicable ambient air quality standard.

## CCPP Unit 8
## Permit Conditions

**Definitions:**

| | |
|---|---|
| Clock Hour: | Any continuous 60-minute period beginning on the hour. |
| Calendar Day: | Any continuous 24-hour period beginning at 12:00 AM or 0000 hours. |
| Year: | Any consecutive twelve-month period of time |
| Heat Input: | All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in Btu/scf. |
| Rolling 3-hour period: | Any three-hour period that begins on the hour and does not include start-up or shutdown periods. |

| | |
|---|---|
| Firing Hours: | Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments. |
| MM Btu: | million British thermal units |
| Gas Turbine Start-up Mode: | The lesser of the first 256 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 27(b) and 27(d). |
| Gas Turbine Shutdown Mode: | The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 27(b) through 27(d) until termination of fuel flow to the Gas Turbine. |
| Specified PAHs: | The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.<br>Benzo[a]anthracene<br>Benzo[b]fluoranthene<br>Benzo[k]fluoranthene<br>Benzo[a]pyrene<br>Dibenzo[a,h]anthracene<br>Indeno[1,2,3-cd]pyrene |
| Corrected Concentration: | The concentration of any pollutant (generally $NO_x$, CO, or $NH_3$) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% $O_2$ by volume on a dry basis. |
| Commissioning Activities: | All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the CCPP Unit#8 construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems. |
| Commissioning Period: | The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange. |

| | |
|---|---|
| Precursor Organic Compounds (POCs): | Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate |
| CEC CPM: | California Energy Commission Compliance Program Manager |
| CCPP Unit#8: | Contra Costa Power Plant Unit 8 |

**Conditions for the Commissioning Period**

1. The owner/operator of the CCPP Unit 8 (CCPP Unit#8) shall minimize emissions of carbon monoxide and nitrogen oxides from S-41 and S-43 Gas Turbines and S-42 and S-44 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period. Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 47 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-41 & S-43 Gas Turbine combustors and S-42 & S-44 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-11 and A-13 SCR Systems and A-12 and A-14 CO Oxidation Catalyst Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-41 & S-43 Gas Turbines and S-42 & S-44 Heat Recovery Steam Generators.

4. Coincident with the as designed operation of A-11 & A-13 SCR Systems, pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall comply with the $NO_x$ and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the CCPP Unit#8 shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired preheater. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-$NO_x$ combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and $NO_x$ continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

6. During the commissioning period, the owner/operator of the CCPP Unit#8 shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   firing hours for each gas turbine and each HRSG
   fuel flow rates to each train
   stack gas nitrogen oxide emission concentrations at P-11 and P-12
   stack gas carbon monoxide emission concentrations P-11 and P-12
   stack gas carbon dioxide concentrations P-11 and P-12

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44). The owner/operator shall use District-approved methods to calculate heat input rates, $NO_x$ mass emission rates, carbon monoxide mass emission rates, and $NO_x$ and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous emission monitors specified in condition 5 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44). After first firing of the turbines and auxiliary boilers, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and $NO_x$ emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-41 Gas Turbine and S-42 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-11 SCR System and/or A-12 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-41 Gas Turbine and S-42 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

9. The total number of firing hours of S-43 Gas Turbine and S-44 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-13 SCR System and/or A-14 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-43 Gas Turbine and S-44 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, $PM_{10}$, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat

Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

11. Combined pollutant mass emissions from the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-41 & S-43).

| | | |
|---|---|---|
| $NO_x$ (as $NO_2$) | 8,400 pounds per calendar day | 400 pounds per hour |
| CO | 13,000 pounds per calendar day | 584 pounds per hour |
| POC (as $CH_4$) | 535 pounds per calendar day | |
| $PM_{10}$ | 624 pounds per calendar day | |
| $SO_2$ | 297 pounds per calendar day | |

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 20. The source test shall determine $NO_x$, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

**Conditions for the Gas Turbines (S-41 & S-43) and the Heat Recovery Steam Generators (HRSGs; S-42 & S-44)**

13. The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on natural gas. (BACT for $SO_2$ and $PM_{10}$)

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,227 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for $NO_x$)

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 53,440 MM Btu per calendar day. (PSD for $PM_{10}$)

16. The combined cumulative heat input rate for the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall not exceed 34,900,000 MM Btu per year. (Offsets)

17. The HRSG duct burners (S-42 and S-44) shall not be fired unless its associated Gas Turbine (S-41 and S-43, respectively) is in operation. (BACT for $NO_x$)

18. Except as provided in Condition No. 8, S-41 Gas Turbine and S-42 HRSG shall be abated by the properly operated and properly maintained A-11 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-11 catalyst bed has reached minimum operating temperature. (BACT for $NO_x$)

19. Except as provided in Condition No. 9, S-43 Gas Turbine and S-44 HRSG shall be abated by the properly operated and properly maintained A-13 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-13 catalyst bed has reached minimum operating temperature. (BACT for $NO_x$)

20. The Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as $NO_2$) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as $NO_2$) at P-12 (the combined exhaust point for the S-43 Gas Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. (PSD for $NO_x$)

    (b) The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any 1-hour period. (BACT for $NO_x$)

    (c) Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed 0.013 lb./MM Btu (HHV) of natural gas fired or 29.22 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed 6 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any rolling 3-hour period. (BACT for CO)

    (e) Ammonia ($NH_3$) emission concentrations at P-11 and P-12 each shall not exceed 10 ppmv, on a dry basis, corrected to 15% $O_2$, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates,

and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (TRMP for $NH_3$)

(f) Precursor organic compound (POC) mass emissions (as $CH_4$) at P-11 and P-12 each shall not exceed 5.6 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)

(g) Sulfur dioxide ($SO_2$) mass emissions at P-11 and P-12 each shall not exceed 6.18 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)

(h) Particulate matter ($PM_{10}$) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or 0.00588 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter ($PM_{10}$) mass emissions at P-11 and P-12 each shall not exceed 13 pounds per hour or 0.00584 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-41 and S-43) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

| | Cold Start-Up (lb./start-up) | Hot Start-Up (lb./start-up) | Shutdown (lb./shutdown) |
|---|---|---|---|
| Oxides of Nitrogen (as NOx) | 452 | 189 | 59 |
| Carbon Monoxide (CO) | 990 | 291 | 73 |
| Precursor Organic Compounds (as $CH_4$) | 109 | 26 | 6 |

22. The Gas Turbines (S-41 and S-43) shall not be in start-up mode simultaneously. (PSD)

23. Total combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44), including emissions generated during Gas Turbine start-ups and shutdowns shall not exceed the following limits during any calendar day:

| | | |
|---|---|---|
| (a) | 1,994 pounds of $NO_x$ (as $NO_2$) per day | (CEQA) |
| (b) | 3,602 pounds of CO per day | (PSD) |
| (c) | 468 pounds of POC (as $CH_4$) per day | (CEQA) |
| (d) | 624 pounds of $PM_{10}$ per day | (PSD) |
| (e) | 297 pounds of $SO_2$ per day | (BACT) |

24. Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44)and the Fuel Gas Preheater (S-45) and the Cooling Tower (S-46), including emissions generated during gas turbine start-ups and shutdowns shall not exceed the following limits during any consecutive twelve-month period:

| | | |
|---|---|---|
| (a) | 174.3 tons of $NO_x$ (as $NO_2$) per year | (Offsets, PSD) |
| (b) | 259.1 tons of CO per year | (Cumulative Increase) |
| (c) | 46.6 tons of POC (as $CH_4$) per year | (Offsets) |
| (d) | 112.2 tons of $PM_{10}$ per year | (Offsets, PSD) |
| (e) | 48.5 tons of $SO_2$ per year | (Cumulative Increase) |

25. The maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limits:

4,102 pounds of formaldehyde per year
506 pounds of benzene per year
38 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

26. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 23(a), 23(b), 24(a), and 24(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(b) Carbon Dioxide ($CO_2$) or Oxygen ($O_2$) concentrations, Nitrogen Oxides ($NO_x$) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.
(c) Ammonia injection rate at A-11 and A-13 SCR Systems
(d) Steam injection rate at S-41 & S-43 Gas Turbine Combustors

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and average hourly pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(e) Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

(f) Corrected $NO_x$ concentrations, $NO_x$ mass emissions (as $NO_2$), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.

Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and 26f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-41, S-42, S-43, and S-44) combined.

(i) the average $NO_x$ mass emissions (as $NO_2$), CO mass emissions, and corrected $NO_x$ and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(j) on an hourly basis, the cumulative total $NO_x$ mass emissions (as $NO_2$) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.

(k) For each calendar day, the average hourly Heat Input Rates, Corrected $NO_x$ emission concentrations, $NO_x$ mass emissions (as $NO_2$), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

(l) on a daily basis, the cumulative total $NO_x$ mass emissions (as $NO_2$) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c) through 23(e), and 24(c) through 24(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter ($PM_{10}$) mass emissions (including condensable particulate matter), and Sulfur Dioxide ($SO_2$) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 26, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, $PM_{10}$, and $SO_2$ emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-41, S-42, S-43, and S-44) combined.

(b) on a daily basis, the 365 day rolling average cumulative total POC, $PM_{10}$, and $SO_2$ mass emissions, for all four sources (S-41, S-42, S-43, and S-44) combined.

(Offsets, PSD, Cumulative Increase)

28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAHs. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 34,900,000 MM Btu/year and the highest emission factor (pounds of pollutant per MM Btu of Heat Input) determined by any source test of the S-41 & S-43 Gas Turbines and/or S-42 & S-44 Heat Recovery Steam Generators. If this calculation method results in an unrealistic mass emission rate (the highest emission factor occurs at a low firing rate) the applicant may use an alternate calculation, subject to District approval. (TRMP)

29. Within 60 days of start-up of the CCPP Unit#8, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 to determine the corrected ammonia ($NH_3$) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding $NH_3$ emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve $NO_x$ emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

30. Within 60 days of start-up of the CCPP Unit#8 and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as $NO_2$), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter ($PM_{10}$) emissions including condensable particulate matter. (BACT, offsets)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total $PM_{10}$ emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other

appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 60 days of start-up of the CCPP Unit#8 and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 28 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

| | | |
|---|---|---|
| Benzene | $\leq$ | 26.8 pounds/year |
| Formaldehyde | $\leq$ | 132 pounds/year |
| Specified PAHs | $\leq$ | 0.18 pounds/year |

(TRMP)

33. The owner/operator of the CCPP Unit#8 shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

34. The owner/operator of the CCPP Unit#8 shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

35. The owner/operator of the CCPP Unit#8 shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

36. The stack height of emission points P-11 and P-12 shall each be at least 195 feet above grade level at the stack base. (PSD, TRMP)

37. The Owner/Operator of CCPP Unit#8 shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval.

(Regulation 1-501)

38. Within 180 days of the issuance of the Authority to Construct for the CCPP Unit#8, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 26, 29, 30 and 32. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

39. Prior to the issuance of the BAAQMD Authority to Construct for the CCPP Unit 8, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and 112.2 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

40. Prior to the start of construction of the CCPP Unit 8, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and 112.2 tons of Particulate Matter less than 10 microns. (Offsets)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the CCPP Unit#8 shall submit an application to the BAAQMD for a major facility review permit within 12 months of the issuance of the PSD Permit. (Regulation 2-6-404.1)

42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the CCPP Unit 8 shall not operate either of the gas turbines until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Regulation 2, Rule 7)

43. The CCPP Unit 8 shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

44. The owner/operator shall take monthly samples of the natural gas combusted at the CCPP Unit#8. The samples shall be analyzed for sulfur content using District-approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. If the results from six consecutive monthly samples show results below 0.5 grains per 100 scf, the owner/operator may discontinue the sampling program with District approval. (cumulative increase)

45. The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be

**Table B-3**
**Gateway Generating Station**
**Results of the CTG Screening Analysis**

| Case | Max. Impact, ug/m3 per 1.0 g/s | | | | |
|---|---|---|---|---|---|
| | 1-hr | 3-hr | 8-hr | 24-hr | annual |
| | 2004 Met Data | | | | |
| 1 | 10.698 | 6.188 | 2.996 | 1.022 | 0.145 |
| 2 | 13.185 | 6.859 | 3.989 | 1.454 | 0.211 |
| 3 | 10.646 | 6.163 | 2.973 | 1.014 | 0.144 |
| 4 | 12.533 | 6.732 | 3.833 | 1.363 | 0.200 |
| 5 | 11.048 | 6.364 | 3.154 | 1.077 | 0.155 |
| 6 | 10.494 | 6.092 | 2.913 | 0.994 | 0.141 |
| 7 | 13.609 | 6.979 | 4.112 | 1.527 | 0.219 |
| 8 | 10.933 | 6.304 | 3.096 | 1.057 | 0.152 |
| | 2005 Met Data | | | | |
| 1 | 12.629 | 4.762 | 2.076 | 1.249 | 0.167 |
| 2 | 14.740 | 6.646 | 3.074 | 1.902 | 0.241 |
| 3 | 12.599 | 4.723 | 2.055 | 1.239 | 0.165 |
| 4 | 14.171 | 6.357 | 2.922 | 1.803 | 0.229 |
| 5 | 12.774 | 5.062 | 2.231 | 1.330 | 0.178 |
| 6 | 12.504 | 4.617 | 2.001 | 1.214 | 0.161 |
| 7 | 15.136 | 6.874 | 3.195 | 1.980 | 0.250 |
| 8 | 12.737 | 4.952 | 2.175 | 1.299 | 0.174 |
| | 2006 Met Data | | | | |
| 1 | 11.574 | 5.657 | 3.217 | 1.291 | 0.157 |
| 2 | 14.091 | 7.289 | 3.811 | 1.887 | 0.225 |
| 3 | 11.506 | 5.650 | 3.197 | 1.283 | 0.156 |
| 4 | 13.583 | 7.050 | 3.694 | 1.780 | 0.215 |
| 5 | 12.063 | 5.809 | 3.355 | 1.356 | 0.168 |
| 6 | 11.314 | 5.629 | 3.142 | 1.261 | 0.152 |
| 7 | 14.465 | 7.449 | 3.912 | 1.965 | 0.234 |
| 8 | 11.884 | 5.697 | 3.307 | 1.332 | 0.164 |

**Table B-3 (cont'd)**

| Emission Rates for Screening Modeling (lb/hr) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Turbine | NOx | | SO2 | | | | CO | | PM10 | |
| Case | 1-hr | annual avg | 1-hr | 3-hr | 24-hr | annual avg | 1-hr | 8-hr | 24-hr | annual avg |
| 1 | 14.11 | 19.69 | 5.498 | 5.498 | 5.498 | 4.31 | 17.18 | 17.18 | 11.0 | 11.59 |
| 2 | 7.93 | 19.69 | 3.089 | 3.089 | 3.089 | 4.31 | 9.65 | 9.65 | 11.0 | 11.59 |
| 3 | 13.40 | 19.69 | 5.221 | 5.221 | 5.221 | 4.31 | 16.31 | 16.31 | 11.0 | 11.59 |
| 4 | 9.22 | 19.69 | 3.593 | 3.593 | 3.593 | 4.31 | 11.23 | 11.23 | 11.0 | 11.59 |
| 5 | 15.18 | 19.69 | 5.917 | 5.917 | 5.917 | 4.31 | 18.49 | 18.49 | 12.0 | 11.59 |
| 6 | 13.40 | 19.69 | 5.221 | 5.221 | 5.221 | 4.31 | 16.31 | 16.31 | 11.0 | 11.59 |
| 7 | 8.39 | 19.69 | 3.269 | 3.269 | 3.269 | 4.31 | 10.21 | 10.21 | 11.0 | 11.59 |
| 8 | 15.18 | 19.69 | 5.917 | 5.917 | 5.917 | 4.31 | 18.49 | 18.49 | 12.0 | 11.59 |

| Turbine Emission Rates for Screening Modeling (g/s) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Turbine | NOx | | SO2 | | | | CO | | PM10 | |
| Case | 1-hr | annual avg | 1-hr | 3-hr | 24-hr | annual avg | 1-hr | 8-hr | 24-hr | annual avg |
| 1 | 1.778 | 2.481 | 0.693 | 0.693 | 0.693 | 0.543 | 2.165 | 2.165 | 1.386 | 1.460 |
| 2 | 0.999 | 2.481 | 0.389 | 0.389 | 0.389 | 0.543 | 1.216 | 1.216 | 1.386 | 1.460 |
| 3 | 1.688 | 2.481 | 0.658 | 0.658 | 0.658 | 0.543 | 2.056 | 2.056 | 1.386 | 1.460 |
| 4 | 1.162 | 2.481 | 0.453 | 0.453 | 0.453 | 0.543 | 1.415 | 1.415 | 1.386 | 1.460 |
| 5 | 1.913 | 2.481 | 0.745 | 0.745 | 0.745 | 0.543 | 2.330 | 2.330 | 1.512 | 1.460 |
| 6 | 1.688 | 2.481 | 0.658 | 0.658 | 0.658 | 0.543 | 2.056 | 2.056 | 1.386 | 1.460 |
| 7 | 1.057 | 2.481 | 0.412 | 0.412 | 0.412 | 0.543 | 1.287 | 1.287 | 1.386 | 1.460 |
| 8 | 1.913 | 2.481 | 0.745 | 0.745 | 0.745 | 0.543 | 2.330 | 2.330 | 1.512 | 1.460 |

| Turbine | Load/ Ambient | Modeled Impacts, ug/m3, by Pollutant and Averaging Period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | NOx | | SO2 | | | | CO | | PM10 | |
| Case | Temp | 1-hr | Annual | 1-hr | 3-hr | 24-hr | Annual | 1-hr | 8-hr | 24-hr | Annual |
| 1 | Cold Base | 22.450 | 0.414 | 8.7482 | 4.287 | 0.8947 | 0.0906 | 27.338 | 6.963 | 1.79 | 0.244 |
| 2 | Cold Low | 14.721 | n/a | 5.7364 | 2.837 | 0.7400 | n/a | 17.926 | 4.852 | 2.64 | n/a |
| 3 | Avg. Base | 21.268 | 0.411 | 8.2876 | 4.054 | 0.8441 | 0.0898 | 25.898 | 6.572 | 1.78 | 0.242 |
| 4 | Avg. Low | 16.465 | n/a | 6.4159 | 3.192 | 0.8162 | n/a | 20.049 | 5.423 | 2.50 | n/a |
| 5 | Avg. Peak | **24.437** | **0.442** | **9.5226** | **4.744** | **1.0111** | **0.0967** | **29.757** | **7.815** | 2.05 | **0.260** |
| 6 | Hot Base | 21.108 | 0.401 | 8.2252 | 4.007 | 0.8293 | 0.0876 | 25.703 | 6.460 | 1.75 | 0.236 |
| 7 | Hot Low | 15.998 | n/a | 6.2340 | 3.068 | 0.8153 | n/a | 19.481 | 5.292 | **2.74** | n/a |
| 8 | Hot Peak | 24.367 | 0.432 | 9.4953 | 4.700 | 0.9932 | 0.0945 | 29.672 | 7.705 | 2.01 | 0.254 |

**Table B-4**
**Gateway Generating Station**
**Emission Rates and Stack Parameters for Refined Modeling**

| | Stack Diam, m | Release Height m | Temp, deg K | Exhaust Flow, m3/s | Exhaust Velocity, m/s | Emission Rates, g/s NOx | SO2 | CO | PM10 |
|---|---|---|---|---|---|---|---|---|---|
| **Averaging Period: One hour** | | | | | | | | | |
| Gas Turbine 1 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | 1.9131 | 0.7455 | 2.3296 | n/a |
| Gas Turbine 2 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | 1.9131 | 0.7455 | 2.3296 | n/a |
| Dewpoint Heater | 0.203 | 4.715 | 422.04 | 0.927 | 28.719 | 0.0494 | 2.310E-03 | 2.408E-02 | n/a |
| Fire Pump Engine | 0.154 | 3.251 | 683.15 | 0.821 | 44.058 | 0.3633 | 3.704E-04 | 2.667E-02 | n/a |
| **Averaging Period: Three hours SOx** | | | | | | | | | |
| Gas Turbine 1 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | n/a | 0.7455 | n/a | n/a |
| Gas Turbine 2 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | n/a | 0.7455 | n/a | n/a |
| Dewpoint Heater | 0.203 | 4.715 | 422.04 | 0.927 | 28.719 | n/a | 2.310E-03 | n/a | n/a |
| Fire Pump Engine | 0.154 | 3.251 | 683.15 | 0.821 | 44.058 | n/a | 1.235E-04 | n/a | n/a |
| **Averaging Period: Eight hours CO** | | | | | | | | | |
| Gas Turbine 1 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | n/a | n/a | 85.6324 | n/a |
| Gas Turbine 2 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | n/a | n/a | 85.6324 | n/a |
| Dewpoint Heater | 0.203 | 4.715 | 422.04 | 0.927 | 28.719 | n/a | n/a | 2.408E-02 | n/a |
| Fire Pump Engine | 0.154 | 3.251 | 683.15 | 0.821 | 44.058 | n/a | n/a | 3.333E-03 | n/a |
| **Averaging Period: 24-hour SOx** | | | | | | | | | |
| Gas Turbine 1 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | n/a | 0.7455 | n/a | n/a |
| Gas Turbine 2 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | n/a | 0.7455 | n/a | n/a |
| Dewpoint Heater | 0.203 | 4.715 | 422.04 | 0.927 | 28.719 | n/a | 2.310E-03 | n/a | n/a |
| Fire Pump Engine | 0.154 | 3.251 | 683.15 | 0.821 | 44.058 | n/a | 1.544E-05 | n/a | n/a |
| **Averaging Period: 24-hour PM10** | | | | | | | | | |
| Gas Turbine 1 | 5.108 | 59.436 | 355.37 | 273.286 | 13.334 | n/a | n/a | n/a | 1.3860 |
| Gas Turbine 2 | 5.108 | 59.436 | 355.37 | 273.286 | 13.334 | n/a | n/a | n/a | 1.3860 |
| Dewpoint Heater | 0.203 | 4.715 | 422.04 | 0.927 | 28.719 | n/a | n/a | n/a | 6.044E-03 |
| Fire Pump Engine | 0.154 | 3.251 | 683.15 | 0.821 | 44.058 | n/a | n/a | n/a | 4.167E-04 |
| WSAC (each, eight cells) | 1.651 | 5.823 | 308.15 | 28.317 | 13.227 | n/a | n/a | n/a | 3.058E-03 |
| **Averaging Period: Annual** | | | | | | | | | |
| Gas Turbine 1 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | 2.4813 | 0.5316 | n/a | 1.4594 |
| Gas Turbine 2 | 5.108 | 59.436 | 355.37 | 408.350 | 19.923 | 2.4813 | 0.5316 | n/a | 1.4594 |
| Dewpoint Heater | 0.203 | 4.715 | 422.04 | 0.927 | 28.719 | 4.939E-02 | 1.733E-03 | n/a | 6.044E-03 |
| Fire Pump Engine | 0.154 | 3.251 | 683.15 | 0.821 | 44.058 | 2.074E-03 | 2.114E-06 | n/a | 5.708E-05 |
| WSAC (each, eight cells) | 1.651 | 5.823 | 308.15 | 28.317 | 13.227 | n/a | n/a | n/a | 3.058E-03 |

**Table B-5**
**Gateway Generating Station**
**Calculation of Inversion Fumigation Impacts**

**CTG Emission Rates, g/s per train**

| Case | NOx | SO2 | CO | PM10 |
|---|---|---|---|---|
| 1 | 1.688 | 0.658 | 2.056 | 1.386 |
| 2 | 1.104 | 0.430 | 1.345 | 1.386 |
| 3 | 1.688 | 0.658 | 2.056 | 1.386 |
| 4 | 1.162 | 0.453 | 1.415 | 1.386 |
| 5 | 1.913 | 0.745 | 2.330 | 1.512 |
| 6 | 1.688 | 0.658 | 2.056 | 1.386 |
| 7 | 1.018 | 0.397 | 1.239 | 1.386 |
| 8 | 1.913 | 0.745 | 2.330 | 1.512 |

**Inversion Breakup Modeling Results from SCREEN3**

| Case | Unit Impacts, ug/m3 per g/s | Maximum One-Hour Avg Impacts, ug/m3, 2 trains | | | | Distance to Maximum (m) |
|---|---|---|---|---|---|---|
| | | NOx | SO2 | CO | PM10 | |
| 1 | 1.035 | 3.4944 | 1.3617 | 4.2552 | 2.8690 | 18,291 |
| 2 | 1.32 | 2.9155 | 1.1361 | 3.5503 | 18.2952 | 15,269 |
| 3 | 1.132 | 3.8219 | 1.4893 | 4.6540 | 15.6895 | 17,107 |
| 4 | 1.402 | 3.2578 | 1.2695 | 3.9671 | 19.4317 | 14,592 |
| 5 | 1.185 | 4.5341 | 1.7668 | 5.5212 | 17.9172 | 16,538 |
| 6 | 1.348 | 4.5512 | 1.7735 | 5.5420 | 18.6833 | 15,032 |
| 7 | 1.816 | 3.6959 | 1.4402 | 4.5005 | 25.1698 | 12,034 |
| 8 | 1.413 | 5.4065 | 2.1068 | 6.5835 | 21.3646 | 14,507 |

**Flat Terrain Modeling Results from SCREEN3**

| Case | Unit Impacts, ug/m3 per g/s | Maximum One-Hour Avg Impacts, ug/m3, 2 trains | | | | Distance to Maximum (m) |
|---|---|---|---|---|---|---|
| | | NOx | SO2 | CO | PM10 | |
| 1 | 0.9819 | 3.3151 | 1.2918 | 4.0369 | 2.7218 | 1,074 |
| 2 | 1.316 | 2.9067 | 1.1327 | 3.5395 | 3.6480 | 1,085 |
| 3 | 1.089 | 3.6767 | 1.4327 | 4.4772 | 3.0187 | 1,149 |
| 4 | 1.521 | 3.5344 | 1.3772 | 4.3038 | 4.2162 | 1,038 |
| 5 | 1.17 | 4.4767 | 1.7444 | 5.4513 | 3.5381 | 1,124 |
| 6 | 1.532 | 5.1724 | 2.0156 | 6.2985 | 4.2467 | 1,035 |
| 7 | 2.068 | 4.2088 | 1.6400 | 5.1250 | 5.7325 | 949 |
| 8 | 1.642 | 6.2827 | 2.4482 | 7.6504 | 4.9654 | 1,014 |

**Adjust unit impacts for longer averaging periods to account for 90-minute duration of fumigation**

| Case | 1-hr unit | 3-hr unit | 8-hr unit | 24-hr unit |
|---|---|---|---|---|
| 1 | 1.035 | 1.008 | 0.992 | 0.985 |
| 2 | 1.320 | 1.318 | 1.317 | 1.316 |
| 3 | 1.132 | 1.111 | 1.097 | 1.092 |
| 4 | 1.521 | 1.521 | 1.521 | 1.521 |
| 5 | 1.185 | 1.178 | 1.173 | 1.171 |
| 6 | 1.532 | 1.532 | 1.532 | 1.532 |
| 7 | 2.068 | 2.068 | 2.068 | 2.068 |
| 8 | 1.642 | 1.642 | 1.642 | 1.642 |

**Table B-5 (cont'd)**

**Calculation of Fumigation Impacts**

| Case/Avg Period | NOx | SO2 | CO | PM10 |
|---|---|---|---|---|
| One-Hour | | | | |
| 1 | 3.4944 | 1.3617 | 4.2552 | - |
| 2 | 2.9155 | 1.1361 | 3.5503 | - |
| 3 | 3.8219 | 1.4893 | 4.6540 | - |
| 4 | 3.5344 | 1.3772 | 4.3038 | - |
| 5 | 4.5341 | 1.7668 | 5.5212 | - |
| 6 | 5.1724 | 2.0156 | 6.2985 | - |
| 7 | 4.2088 | 1.6400 | 5.1250 | - |
| 8 | **6.2827** | **2.4482** | **7.6504** | - |
| 3 Hours | | | | |
| 1 | - | 1.1941 | - | - |
| 2 | - | 1.0209 | - | - |
| 3 | - | 1.3149 | - | - |
| 4 | - | 1.2395 | - | - |
| 5 | - | 1.5801 | - | - |
| 6 | - | 1.8140 | - | - |
| 7 | - | 1.4760 | - | - |
| 8 | - | **2.2034** | - | - |
| 8 Hours | | | | |
| 1 | - | - | 2.8545 | - |
| 2 | - | - | 2.4791 | - |
| 3 | - | - | 3.1572 | - |
| 4 | - | - | 3.0127 | - |
| 5 | - | - | 3.8251 | - |
| 6 | - | - | 4.4089 | - |
| 7 | - | - | 3.5875 | - |
| 8 | - | - | **5.3553** | - |
| 24 Hours | | | | |
| 1 | - | 0.5185 | - | 1.0924 |
| 2 | - | 0.4532 | - | 1.4595 |
| 3 | - | 0.5745 | - | 1.2105 |
| 4 | - | 0.5509 | - | 1.6865 |
| 5 | - | 0.6983 | - | 1.4164 |
| 6 | - | 0.8062 | - | 1.6987 |
| 7 | - | 0.6560 | - | **2.2930** |
| 8 | - | **0.9793** | - | 1.9862 |

**Table B-6**
**Gateway Generating Station**
**Calculation of Shoreline Fumigation Impacts**

**Emission Rates, g/s per CTG**

| Case | NOx | SO2 | CO | PM10 |
|---|---|---|---|---|
| 1 | 1.688 | 0.658 | 2.056 | 1.386 |
| 2 | 1.104 | 0.430 | 1.345 | 1.386 |
| 3 | 1.688 | 0.658 | 2.056 | 1.386 |
| 4 | 1.162 | 0.453 | 1.415 | 1.386 |
| 5 | 1.913 | 0.745 | 2.330 | 1.512 |
| 6 | 1.688 | 0.658 | 2.056 | 1.386 |
| 7 | 1.018 | 0.397 | 1.239 | 1.386 |
| 8 | 1.913 | 0.745 | 2.330 | 1.512 |

**Shoreline Fumigation Breakup Modeling Results from SCREEN3**

| | Unit Impacts, ug/m3 per g/s | | | | | Distance to Maximum |
|---|---|---|---|---|---|---|
| Case | TIBL 2 | TIBL 3 | TIBL 4 | TIBL 5 | TIBL 6 | (m) |
| 1 | 0.713 | 1.941 | 3.670 | 5.558 | 7.334 | 1,553 |
| 2 | 0.897 | 2.541 | 4.876 | 7.429 | 9.756 | 1,188 |
| 3 | 0.776 | 2.144 | 4.075 | 6.184 | 8.148 | 1,409 |
| 4 | 0.948 | 2.710 | 5.220 | 7.978 | 10.450 | 1,111 |
| 5 | 0.811 | 2.255 | 4.298 | 6.528 | 8.595 | 1,340 |
| 6 | 0.915 | 2.601 | 4.998 | 7.624 | 10.000 | 1,159 |
| 7 | 1.183 | 3.559 | 6.956 | 10.710 | 13.890 | 833 |
| 8 | 0.954 | 2.732 | 5.265 | 8.049 | 10.540 | 1,102 |

**Highest Shoreline Fumigation Breakup Modeling Results (TIBL = 6)**

| | Impacts, ug/m3 per | Maximum One-Hour Avg Impacts, ug/m3, 2 trains | | | | Distance to Maximum |
|---|---|---|---|---|---|---|
| Case | g/s | NO2 | SO2 | CO | PM10 | (m) |
| 1 | 7.334 | 24.76 | 9.65 | 30.15 | 20.33 | 1,647 |
| 2 | 9.76 | 21.55 | 8.40 | 26.24 | 27.04 | 1,144 |
| 3 | 8.148 | 27.51 | 10.72 | 33.50 | 22.59 | 1,409 |
| 4 | 10.45 | 24.28 | 9.46 | 29.57 | 28.97 | 1,111 |
| 5 | 8.595 | 32.89 | 12.81 | 40.05 | 25.99 | 1,340 |
| 6 | 10.00 | 33.76 | 13.16 | 41.11 | 27.72 | 1,159 |
| 7 | 13.89 | 28.27 | 11.02 | 34.42 | 38.50 | 855 |
| 8 | 10.54 | 40.33 | 15.71 | 49.11 | 31.87 | 1,102 |

**Table B-6 (cont'd)**

**Flat Terrain Modeling Results from SCREEN3**

| Case | Impacts, ug/m3 per g/s | Maximum One-Hour Avg Impacts, ug/m3, 2 trains | | | | Distance to Maximum (m) |
|---|---|---|---|---|---|---|
| | | NOx | SO2 | CO | PM10 | |
| 1 | 0.9754 | 3.2932 | 1.2833 | 4.0101 | 2.7038 | 1,075 |
| 2 | 1.242 | 2.7433 | 1.0690 | 3.3405 | 3.4428 | 1,104 |
| 3 | 1.089 | 3.6767 | 1.4327 | 4.4772 | 3.0187 | 1,149 |
| 4 | 1.521 | 3.5344 | 1.3772 | 4.3038 | 4.2162 | 1,038 |
| 5 | 1.17 | 4.4767 | 1.7444 | 5.4513 | 3.5381 | 1,124 |
| 6 | 1.532 | 5.1724 | 2.0156 | 6.2985 | 4.2467 | 1,035 |
| 7 | 2.068 | 4.2088 | 1.6400 | 5.1250 | 5.7325 | 949 |
| 8 | 1.642 | 6.2827 | 2.4482 | 7.6504 | 4.9654 | 1,014 |

**Adjust unit impacts for longer averaging periods to account for 180-minute duration of fumigation (ug/m3 per g/s)**

| Case | 1-hr unit | 3-hr unit | 8-hr unit | 24-hr unit |
|---|---|---|---|---|
| 1 | 7.334 | 7.334 | 3.360 | 1.770 |
| 2 | 9.76 | 9.76 | 4.435 | 2.306 |
| 3 | 8.148 | 8.148 | 3.736 | 1.971 |
| 4 | 10.45 | 10.45 | 4.869 | 2.637 |
| 5 | 8.595 | 8.595 | 3.954 | 2.098 |
| 6 | 10.00 | 10.00 | 4.708 | 2.591 |
| 7 | 13.89 | 13.89 | 6.501 | 3.546 |
| 8 | 10.54 | 10.54 | 4.979 | 2.754 |

**Table B-6 (cont'd)**

**Calculation of Shoreline Fumigation Impacts**

| Case/Avg Period | NO2 | SO2 | CO | PM10 |
|---|---|---|---|---|
| One-Hour | | | | |
| 1 | 24.76 | 9.65 | 30.15 | - |
| 2 | 21.55 | 8.40 | 26.24 | - |
| 3 | 27.51 | 10.72 | 33.50 | - |
| 4 | 24.28 | 9.46 | 29.57 | - |
| 5 | 32.89 | 12.81 | 40.05 | - |
| 6 | 33.76 | 13.16 | 41.11 | - |
| 7 | 28.27 | 11.02 | 34.42 | - |
| 8 | **40.33** | **15.71** | **49.11** | - |
| 3 Hours | | | | |
| 1 | - | 8.68 | - | - |
| 2 | - | 7.56 | - | - |
| 3 | - | 9.65 | - | - |
| 4 | - | 8.52 | - | - |
| 5 | - | 11.53 | - | - |
| 6 | - | 11.84 | - | - |
| 7 | - | 9.91 | - | - |
| 8 | - | **14.14** | - | - |
| 8 Hours | | | | |
| 1 | - | - | 9.67 | - |
| 2 | - | - | 8.35 | - |
| 3 | - | - | 10.75 | - |
| 4 | - | - | 9.64 | - |
| 5 | - | - | 12.90 | - |
| 6 | - | - | 13.55 | - |
| 7 | - | - | 11.28 | - |
| 8 | - | - | **16.24** | - |
| 24 Hours | | | | |
| 1 | - | 0.93 | - | 1.96 |
| 2 | - | 0.79 | - | 2.56 |
| 3 | - | 1.04 | - | 2.19 |
| 4 | - | 0.96 | - | 2.92 |
| 5 | - | 1.25 | - | 2.54 |
| 6 | - | 1.36 | - | 2.87 |
| 7 | - | 1.12 | - | **3.93** |
| 8 | - | **1.64** | - | 3.33 |

**Table B-7**
**Gateway Generating Station**
**Emission Rates and Stack Parameters for Modeling Startup Impacts**
One CTG in startup, per Condition 22

| | Stack Diam, m | Stack Height, m | Exh Temp, Deg K | Exhaust Flow, m3/s | Exhaust Velocity, m/s | Em Rates, g/s | |
|---|---|---|---|---|---|---|---|
| | | | | | | NOx | CO |
| One unit in startup | 5.108 | 59.436 | 355.222 | 273.286 | 13.334 | 20.16 | 113.40 |
| One unit in operation (Case 5) | 5.108 | 59.436 | 355.222 | 408.350 | 19.923 | 1.91 | 2.33 |
| Dewpoint Heater | 0.203 | 4.715 | 421.889 | 0.927 | 28.719 | 0.05 | 0.02 |

**Table B-8**
**Gateway Generating Station**
**Emission Rates and Stack Parameters for Modeling Commissioning Impacts**

| | Stack Diam, m | Stack Height, m | Exh Temp, Deg K | Exhaust Flow, m3/s | Exhaust Velocity, m/s | Em Rates, g/s | |
|---|---|---|---|---|---|---|---|
| | | | | | | NOx | CO |
| Gas Turbine 1 | 5.108 | 59.436 | 355.222 | 273.286 | 13.334 | 25.20 | 252.00 |
| Gas Turbine 2 | 5.108 | 59.436 | 355.222 | 273.286 | 13.334 | 25.20 | 252.00 |

**Max. Modeled Impact During Commissioning of Two CTGs**

| | Max Modeled Conc, ug/m3 | Background, ug/m3 | Total Impact, ug/m3 | State Standard, ug/m3 | Federal Standard, ug/m3 |
|---|---|---|---|---|---|
| **NO2, 1 hr ozone lmtd** | 152 | 109 | 261 | 338 | -- |
| **CO, 1 hr** | 4,065 | 5,125 | 9,190 | 23,000 | 40,000 |
| **CO, 8 hr** | 1,042 | 2,133 | 3,175 | 10,000 | 10,000 |

Attachment B-1

Modeling Protocol and BAAQMD Comments

sierra research

# Gateway Generating Station Modeling Protocol

prepared for:

Pacific Gas & Electric Company

August 2007

prepared by:

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1801 J Street
Sacramento, California 95811

# Gateway Generating Station
# Modeling Protocol

August 2007

Prepared for
Pacific Gas & Electric Company

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# Gateway Generating Station
# Modeling Protocol

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Appendix A – Surface Parameters to be used in AERMET Stage 3 Processing

Appendix B – Information on CTDMPLUS Model

# Gateway Generating Station
# Modeling Protocol
# August 2007

## 1. Background

On behalf of Pacific Gas & Electric Company (PG&E), Sierra Research is submitting this modeling protocol to the Bay Area Air Quality Management District (BAAQMD or District) and California Energy Commission (CEC) for approval of the air dispersion and health risk assessment modeling proposed to be conducted in support of modifications to the Gateway Generating Station (GGS or Project) BAAQMD Authority to Construct and the CEC Conditions of Certification. GGS was permitted by the BAAQMD and licensed by the CEC in 2001 as Contra Costa Power Project Unit 8 (CC8), which was then owned by Mirant Delta LLC. Mirant commenced construction of the facility in late 2001, but suspended construction activities in February 2002. Ownership of the project was transferred to PG&E in November 2006, and construction recommenced in early February 2007. The BAAQMD renewed the Authority to Construct in June 2007. In August 2007, the CEC approved several changes to the project that did not require changes to the BAAQMD Authority to Construct; the most notable air quality-related change was the replacement of the original wet cooling tower with an air-cooled condenser and small wet surface-air cooler.

PG&E has reviewed the permit conditions and emission limits in the Authority to Construct and the Conditions of Certification and has determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. In the application to be filed with the District and the CEC, PG&E will propose the following changes to the permitted facility:

- Eliminate the 10-cell wet cooling tower and replace it with a dry cooling system, including an exempt wet surface air cooler;[1]
- Replace the permitted natural gas-fired dew point gas heater with a smaller unit and increase allowable daily hours of operation;
- Change the allowable emission limits for the gas turbines during startup operations;

[1] As indicated above, this amendment has already been approved by the CEC. However, since the installation of the dry cooling system did not require a change to the BAAQMD ATC, the BAAQMD permit does not yet include this project modification.

- Reduce the permitted hourly emission rates for NOx and $PM_{10}$ and increase the allowable ammonia slip limit, based on current BACT and on operating experience from other 7FA gas turbine facilities;
- Reduce the annual average allowable sulfur content of the natural gas;
- Reduce the permitted hourly emission rates and increase the annual emission limit for CO, based on current BACT and operating experience from other 7FA gas turbine facilities;
- Change the allowable emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Replace the electric motor-driven fire water pump with a 300 kW Diesel fire pump engine.

Annual emission limits of all pollutants except CO will be reduced or will stay the same as the limits in the existing ATC and conditions of certification. The proposed increase in annual CO emissions will exceed 100 tons per year, so the Project will be a major modification of the existing major source under District New Source Review regulations.

PG&E is also proposing to increase allowable short-term emissions of NOx and CO from the CTGs/HRSGs during startups and commissioning operations. No increases in short-term or annual $SO_2$ or $PM_{10}$ emissions will result from the proposed permit modifications.

Impacts from operation of the facility will be compared to the following thresholds:

| Air Quality Criteria | $NO_2$ | CO |
|---|---|---|
| PSD Significant Impact Levels | n/a[a,b] | √ |
| BAAQMD Significant Impact Levels | n/a[a] | √ |
| PSD Monitoring Exemption Levels | n/a[a] | √ |
| Ambient Air Quality Standards (AAQS) | √[c] | √ |

Notes:
a. PSD significant impact and monitoring exemption levels apply only if the project is subject to PSD review. Because the project will not result in an increase in permitted annual NOx emissions, the project is not subject to PSD review for $NO_2$.
b. n/a: Not applicable.
c. State one-hour average $NO_2$ standard only.

## 2. Project Location

The project is located at 3225 Wilbur Avenue, Antioch. The location of the site is approximately 4208.2 km N, 609.0 km E. The nominal site elevation is 2 meters (6.6 feet) above mean sea level.

## 3. Emission Sources

GGS is a 530-megawatt (MW) nominal combined cycle electric generation facility. Permitted equipment at GGS consists of two GE 7FA natural gas-fired combustion turbines with supplemental duct fired heat recovery steam generators (S-41, S-42, S-43 and S-44), a natural gas fired dew point gas heater (S-45), a 10-cell cooling tower (S-46) and an oil-water separator (S-48). The proposed equipment changes and their potential emissions and air quality impacts are listed below.

- Replace the 10-cell cooling tower (S-46) with air-cooled condenser and small wet surface-air cooler, both exempt from permitting, reducing $PM_{10}$ emissions;
- Replace the natural gas-fired dew point gas heater (S-45) with a smaller unit and increase allowable daily operation, reducing hourly NOx emissions (no increase in annual NOx emissions); and
- Add a new Diesel fire pump engine, adding a source of Diesel particulate matter (a toxic air contaminant).

## 4. Meteorological Data

The ambient air quality analysis will use four years of meteorological data (1994 through 1997) collected at the existing Contra Costa Power Plant less than one-half of a mile from the proposed project site. Upper air data will be taken from Oakland. The BAAQMD's standard maximum mixing height of 600 meters will be used. The meteorological data processor AERMET will be used to generate AERMOD-compatible meteorological data for air dispersion modeling.

## 5. Site Representation – Meteorological Data

USEPA defines the term "site specific data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Specifically, the meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and USEPA's guidance on the use of on-site monitoring data are also outlined in the "*Meteorological Monitoring Guidance for Regulatory Modeling Applications*" (2000). The representativeness of the data depends on (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected. The meteorological data collected at

the Contra Costa Power Plant have previously been accepted by the BAAQMD and CEC staffs as representative of conditions at the project site.[2]

## 6. Existing Ambient Air Quality Data

Background ambient air quality data for the project area during 2004-2006 will be obtained from the monitoring site nearest to the project site. The Pittsburg 10th Street monitoring site is the nearest with background data for CO and $NO_2$. Modeled concentrations will be added to these representative background concentrations to determine compliance with the CAAQS and NAAQS.

## 7. Air Quality Dispersion Models

### *Overview*

The following USEPA air dispersion models are proposed for use to quantify pollutant impacts on the surrounding environment based on the emission sources' operating parameters and their locations:

- American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model, also known as AERMOD (Version 07026);
- Building Profile Input Program – Plume Rise Model Enhancements (BPIP-PRIME, current version 04274); and
- SCREEN3 (Version 96043).

The following models are not expected to be used, but they are listed in the event that an optional specialized modeling analysis is necessary for the project.

- Complex Terrain SCREEN (CTSCREEN, Version 94111); and
- Complex Terrain Dispersion Model (CTDMPLUS, Version 93228).

The three primary models listed above, and how they are used, are discussed below. Further information on the use of CTDMPLUS and CTSCREEN is provided in Appendix B.

### *Simple, Complex, and Intermediate Terrain Impacts*

For modeling project emissions in simple, complex, and intermediate terrain, the USEPA-recommended guideline model AERMOD will be used with the AERMET-processed hourly meteorological data from the Contra Costa Power Plant monitoring station during 1994-1997. The AERMOD model requires hourly

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[2] BAAQMD, Final Determination of Compliance, Contra Costa Power Plant Unit 8 Project, February 2, 2001; and CEC Final Staff Assessment for Contra Costa Power Plant Unit 8 Project (00-AFC-1), March 2001.

meteorological data consisting of wind vector and speed (with reference height), temperature (with reference height), Monin-Obukhov length, surface roughness length, heights of the mechanically- and convectively-generated boundary layers, surface friction velocity, convective velocity scale, and vertical potential temperature gradient in the 500-meter layer above the planetary boundary layer. The model assumes that there is no variability in meteorological parameters over a one-hour time period, hence the term "steady-state." The AERMOD model allows input of multiple sources and source groupings, eliminating the need for multiple model runs. Complex phenomena such as building-induced plume downwash are treated in this model. The parameters we propose to use in the AERMET Stage 3 processing to characterize surface conditions are shown in detail in Appendix A.

Standard AERMOD control parameters will be used (stack tip downwash, non-screening mode, non-flat terrain, sequential meteorological data check employed). Stack-tip downwash, which adjusts the effective stack height downward following the methods of Briggs (1972) for cases where the stack exit velocity is less than 1.5 times the wind speed at stack top, will be selected per USEPA and BAAQMD guidance. Other options that will be used in accordance with BAAQMD guidance include gradual plume rise and buoyancy-induced dispersion. As for the original modeling analysis for this facility, the rural default option will be used.[3]

***Ozone Limiting Method***

For evaluating compliance with the state one-hour average $NO_2$ standard, the tiered screening approach as described in "Supplement C To The Guideline On Air Quality Models (Revised)," EPA, August 1995 (EPA-450/2-78-027R-C) will be used. The initial assumption will be that all of the NOx converts to $NO_2$. If maximum hourly $NO_2$ concentrations need to be examined in more detail, the Plume Volume Molar Ratio Method (PVMRM) adaptation of the Ozone Limiting Method (Cole and Summerhays, 1979) will be used. AERMOD PVMRM will be used to calculate the $NO_2$ concentration based on the PVMRM method and hourly ozone data. Hourly ozone data collected at the Pittsburg 10$^{th}$ Street monitoring station during the years 1994-1997 will be used in conjunction with PVMRM to calculate hourly $NO_2$ concentrations from hourly NOx concentrations. Missing hourly ozone data will be substituted prior to use with day-appropriate values (e.g., from the previous day, or the next day, for the same hour). Any other missing hourly ozone data will be substituted with 40 ppb ozone (typical ozone tropospheric background level). The PVMRM involves an initial comparison of the estimated maximum NOx concentration and the ambient $O_3$ concentration in the plume after dilution to determine whether NO or $O_3$ is the limiting factor to $NO_2$ formation. If the $O_3$ concentration is greater than the maximum

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[3] The rural vs. urban option in AERMOD is primarily designed to set the fraction of incident heat flux that is transferred into the atmosphere. This fraction becomes important in urban areas having an appreciable "urban heat island" effect due to a large presence of land covered by concrete, asphalt, and buildings. This situation does not exist for the proposed project site.

NOx concentration, total conversion is assumed. If the NOx concentration is greater than the remaining $O_3$ concentration, the formation of $NO_2$ is limited by the remaining ambient $O_3$ concentration. In this case, the $NO_2$ concentration is set equal to the $O_3$ concentration plus a correction factor that accounts for in-stack and near-stack thermal conversion.

***Fumigation***

The SCREEN3 model will be used to evaluate inversion breakup and shoreline fumigation impacts for short-term averaging periods (24 hours or less), as appropriate. The methodology in USEPA, 1992 (Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised) and BAAQMD guidance (*http://www.baaqmd.gov/pmt/air_toxics/permit_ modeling/pmt_modeling_guidance.pdf*) will be followed for these analyses. Combined impacts for all sources under fumigation conditions will be evaluated, based on USEPA and applicable BAAQMD modeling guidelines.

## 8. Good Engineering Practice (GEP) Stack Height and Downwash

AERMOD can account for building downwash effects on dispersing plumes. Stack locations and heights and building locations and dimensions will be input to BPIP-PRIME. The first part of BPIP-PRIME determines and reports on whether a stack is being subjected to wake effects from a structure or structures. The second part calculates direction-specific building dimensions for each structure that are used by AERMOD to evaluate wake effects. The BPIP-PRIME output is formatted for use in AERMOD input files.

## 9. Receptor Selection

Receptor and source base elevations will be determined from USGS Digital Elevation Model (DEM) data using the 7½-minute format (10- to 30-meter spacing between grid nodes). All coordinates will be referenced to UTM North American Datum 1927 (NAD27), Zone 11. The AERMOD receptor elevations will be interpolated among the DEM nodes according to standard AERMAP procedure. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option will be chosen; hills will not be imported into AERMOD for CTDM-like processing.

Cartesian coordinate receptor grids will be used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. A 250-meter resolution coarse receptor grid will be developed and will extend outwards at least 10 km (or more as necessary to calculate the significant impact area).

For the full impact analyses, a nested grid will be developed to fully represent the maximum impact area(s). This grid will have 25-meter resolution along the facility fence-line in a single tier of receptors composed of four segments extending out to 100 meters from the fenceline, 100-meter resolution from 100 meters to 1,000 meters from the fenceline, and 250-meter spacing out to at least 10 km from the site. When maximum

first-high or maximum second-high impacts occur in the 250-meter spaced area, additional refined receptor grids with 25-meter resolution will be placed around the maximum coarse grid impacts and extended out 1,000 meters in all directions. Concentrations within the facility fenceline will not be calculated.

## 10. Modeling Scenarios

The only changes proposed for the emissions limitations affect short-term emission limits and/or short-term standards. Therefore, the following scenarios will be modeled:

- 1-hr and 8-hr average CO during turbine startup/shutdown and turbine commissioning; and
- 1-hr average $NO_2$ during turbine startup/shutdown and turbine commissioning.

In the modeling analysis, startup conditions will be represented by minimum load (50% load) stack parameters and proposed permitted emission rates.

### *Details of Operating Scenarios*

The following table gives more detail on the operating modes to be modeled.

| Operating Modes of the Combustion Gas Turbines | |
|---|---|
| Mode | Description |
| Commissioning | The process of fine-tuning each of the turbines. The facility will follow a systematic approach to optimize performance of the turbines and the associated control equipment. Emissions are expected to be greater during commissioning than during normal operation for NOx, CO, and POC. This one-time mode affects only the initial year of operation. |
| Startup/Shutdown | Startup NOx and CO emissions are higher because low-NOx combustors are not able to operate in their optimal mode, and the SCR and oxidation catalysts have not reached optimal temperature to begin the chemical reactions needed to reduce NOx and oxidize CO in the turbine/HRSG exhaust. Shutdown occurs at the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. Typically, the shutdown process will have lower emissions than the startup process so will not be modeled separately. |

### *Ambient Air Quality Impact Analyses*

In evaluating the impacts of the proposed project on ambient air quality, we will model the ambient impacts of the project, add those impacts to background concentrations, and compare the results to the state and federal ambient standards for $NO_2$ and CO.

## 11. Class I Area Impact Methodology

No changes are being proposed that would affect annual emissions of pollutants that interfere with visibility or produce acid deposition ($NO_2$, $SO_2$ or $PM_{10}$), and hence, no significant impacts are expected on Class I areas.

## 12. Screening Health Risk Analysis

District Regulation 2, Rule 5 requires preconstruction review for potential health impacts from new and modified sources of toxic air contaminants. Toxic emissions are estimated for all sources within a proposed project; if emissions from a proposed project exceed the BAAQMD regulatory trigger levels, a Health Risk Screening Analysis (HRSA) is required to determine project risk and risk from each source. A HRSA was prepared for the original permitting and licensing of the CC8 project. This HRSA will be updated to reflect the proposed 10 ppm ammonia slip level, the proposed new Diesel emergency fire pump engine, and the most current risk values published by OEHHA. The HRA modeling will be prepared using ARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.3, October 18, 2005). The HARP model will be used to assess cancer risk as well as non-cancer chronic and acute health hazards. The HRA will include the four following pathways: inhalation, dermal absorption, soil and mother's milk ingestion.

Because the HARP model incorporates the previously USEPA-approved model ISCST3, a special methodology will be employed to be consistent with using AERMOD for the air dispersion modeling and retain the health values and risk computations provided by HARP Version 1.3. The OEHHA/ARB-approved methodology used to prepare the HRA has been described by the ARB[4] and is described below. Its use has also been accepted by both the CEC and the District for previous power plant projects.

Modeling Inputs – The risk assessment module of the HARP model is run using unit ground level impacts to obtain derived cancer risks for each toxic air contaminant (TAC). The HARP model output is cancer risk by TAC and pathway for each type of analysis, based on an exposure of 1.0 $\mu g/m^3$. Individual cancer risks are expressed in units of risk per $\mu g/m^3$ of exposure. To calculate the weighted risk for each source, the annual average emission rate in grams per second for each TAC will be multiplied by the individual cancer risk for that TAC in units of $(\mu g/m^3)^{-1}$. The resulting weighted cancer risks for each TAC will then be summed for the source. The same approach will be used to determine the non-cancer acute and chronic health hazards associated with the Project.

Health risk from exposure to a carcinogenic TAC is calculated as the product of the exposure concentration times a factor representing the risk per unit concentration (i.e., unit risk) for the TAC. In the case of cancer risk, the risk per unit concentration depends on breathing rate, the cancer potency factor of the TAC, dimensional factors, and other

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[4] ARB. Part B of Topic 8 of the HARP How-To Guides: How to Perform Health Analyses Using a Ground Level Concentration.

terms involving non-inhalation pathways, when relevant. In the case of chronic and acute non-cancer impacts, the unit impact or health hazard per unit concentration is normally calculated as 1 divided by the Reference Exposure Level (REL, expressed as a concentration in $\mu g/m^3$) for the TAC.

Exposure concentration is calculated as the product of the actual emission rate (in grams per second) of the TAC times the concentration per unit of emission (i.e., an emission rate of 1 g/s), which is the output from the AERMOD air dispersion modeling calculation. This exposure concentration is the "Unit Concentration."

The way that HARP usually works is for the program to automatically pass the "Unit Concentration" for a given source and receptor into its risk module where it is multiplied by the actual emission rate (in g/s) for each TAC and the "Unit Risk" for the TAC to produce the calculated risk for the TAC. This is done for all TACs emitted by a source and the summed cancer risk, or non-cancer health impact for common toxic endpoints in the case of chronic and acute risk, is the total risk or non-cancer health impact at that receptor from that source. The total cancer risk or non-cancer health impact at a receptor is the sum of the risks or health impacts from all of the sources.

Because HARP is not designed to pass AERMOD "Unit Concentration" outputs to its Risk Module, an alternative procedure can be used. The calculation of cancer risk or non-cancer health impact does not require the variables to be multiplied in any particular order. Therefore, the final result will be the same if, for a given source, the "Unit Risk" for a TAC is multiplied by the actual emissions (g/s) for the TAC, and these products are added together to give a "Source Strength" for the source. The "Source Strength" is then used as the source emission rate in AERMOD.

This special methodology thus uses HARP to calculate the "Unit Risks" for all carcinogenic TACs and unit chronic and acute health impacts for all non-carcinogenic TACs, including all required exposure pathways and toxic endpoints as well as receptor types, including residents and workers. The unit risk or unit health impact for each TAC from a source is multiplied by the emission rate of that TAC from the source. These products are summed for all TACs emitted by the source. This is done for each source. Finally, the resulting "Source Strengths" for each source are used as emission rates in an AERMOD calculation. The resulting risks are reported in the AERMOD output.

It is expected that the District will conclude that the new Diesel fire pump engine satisfies the requirements of toxics Best Available Control Technology, for which the maximum allowable cancer risk is 10 in one million.

### 13. Final Modeling Submittal

The final modeling analyses will include the following materials:

- Emissions calculations, modeled emission rates, and stack parameters (diameter, height, exit velocity, stack gas temperature, stack base height above sea level);
- Summaries of maximum modeled impacts for each air quality scenario;

- All modeling inputs and outputs (including BPIP-PRIME, ozone data and meteorological files) in electronic format, together with a description of all filenames;
- Plot plan showing emission points, nearby buildings (including dimensions), cross-section lines, property lines, fencelines, roads, and UTM coordinates;
- A table showing building heights used in the modeling analysis; and
- Concentration isopleths maps for each criteria pollutant and averaging time combination.

The HRA results will include AERMOD output files, spreadsheets that show the risk calculation procedures, a figure showing the locations of the maximum acute, chronic and cancer risks from the project, and a detailed description of the methodology.

## 14. REFERENCES


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# Appendix A

## Surface Parameters to be used for AERMET Stage 3 Processing

**Surface Parameters to be Used for Stage 3 AERMET Processing**
**Gateway Generating Station**

**Spring - average**

| Sector | Land use (met station) | Suface roughness (m) | Land use (application site) | Albedo | Bowen ratio |
|---|---|---|---|---|---|
| 1. 305$^0$-40$^0$ | open water with distant shore | 0.003 | open water with distant shore | 0.12 | 0.10 |
| 2. 40$^0$-90$^0$ | open water | 0.001 | open water | 0.12 | 0.10 |
| 3.90$^0$-120$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 1.00 |
| 4.120$^0$-200$^0$ | Gentle slope with distant residences (grassland) | 0.100 | Gentle slope with distant residences (grassland) | 0.18 | 0.40 |
| 5.200$^0$-270$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 1.00 |
| 6.270$^0$-305$^0$ | open water | 0.001 | open water | 0.12 | 0.10 |

**Summer - dry**

| Sector | Land use (met station) | Suface roughness (m) | Land use (application site) | Albedo | Bowen ratio |
|---|---|---|---|---|---|
| 1. 305$^0$-40$^0$ | open water with distant shore | 0.003 | open water with distant shore | 0.10 | 0.10 |
| 2. 40$^0$-90$^0$ | open water | 0.001 | open water | 0.10 | 0.10 |
| 3.90$^0$-120$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 4.00 |
| 4.120$^0$-200$^0$ | Gentle slope with distant residences (grassland) | 0.100 | Gentle slope with distant residences (grassland) | 0.18 | 2.00 |
| 5.200$^0$-270$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 4.00 |
| 6.270$^0$-305$^0$ | open water | 0.001 | open water | 0.10 | 0.10 |

**Autumn - dry**

| Sector | Land use (met station) | Suface roughness (m) | Land use (application site) | Albedo | Bowen ratio |
|---|---|---|---|---|---|
| 1. 305$^0$-40$^0$ | open water with distant shore | 0.003 | open water with distant shore | 0.14 | 0.10 |
| 2. 40$^0$-90$^0$ | open water | 0.001 | open water | 0.14 | 0.10 |
| 3.90$^0$-120$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 4.00 |
| 4.120$^0$-200$^0$ | Gentle slope with distant residences (grassland) | 0.100 | Gentle slope with distant residences (grassland) | 0.18 | 2.00 |
| 5.200$^0$-270$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 4.00 |
| 6.270$^0$-305$^0$ | open water | 0.001 | open water | 0.14 | 0.10 |

**Winter - wet**

| Sector | Land use (met station) | Suface roughness (m) | Land use (application site) | Albedo | Bowen ratio |
|---|---|---|---|---|---|
| 1. 305$^0$-40$^0$ | open water with distant shore | 0.003 | open water with distant shore | 0.20 | 0.10 |
| 2. 40$^0$-90$^0$ | open water | 0.001 | open water | 0.20 | 0.10 |
| 3.90$^0$-120$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 0.50 |
| 4.120$^0$-200$^0$ | Gentle slope with distant residences (grassland) | 0.100 | Gentle slope with distant residences (grassland) | 0.18 | 0.50 |
| 5.200$^0$-270$^0$ | Industrial (urban) | 0.600 | Industrial (urban) | 0.14 | 0.50 |
| 6.270$^0$-305$^0$ | open water | 0.001 | open water | 0.20 | 0.10 |

Sources for proposed parameter values:
USER'S GUIDE FOR THE AERMOD METEOROLOGICAL PREPROCESSOR (AERMET)

| | Bowen ratio |
|---|---|
| 0.10 | Unfrozen water |
| 1.00 | Grassland - dry - spring |
| 2.00 | Grassland - dry - summer, autumn, winter |
| 2.00 | Urban - dry - spring, winter |
| 4.00 | Urban - dry - summer, autumn |
| 0.30 | Grassland - wet - spring |
| 0.40 | Grassland - wet - summer |
| 0.50 | Grassland - wet - autumn, winter |
| 0.50 | Urban - wet - spring, winter |
| 1.00 | Urban - wet - summer, autumn |
| 0.40 | Grassland - avg. - spring |
| 0.80 | Grassland - avg. - summer |
| 1.00 | Grassland - avg. - autumn |
| 1.50 | Grassland - avg. - winter |
| 1.00 | Urban - avg. - spring |
| 2.00 | Urban - avg. - summer, autumn |
| 1.50 | Urban - avg. - winter |

| | Albedo |
|---|---|
| 0.12 | Water - spring |
| 0.10 | Water - summer |
| 0.14 | Water - autumn |
| 0.20 | Water - winter |
| 0.14 | Urban |
| 0.18 | Grassland |

from 'An Introduction to Boundary Layer Meteorology' by Roland B. Stull, Fig. 9.6, p. 380.

| | Roughness Lengths (m) |
|---|---|
| 0.600 | Centers of small towns |
| 0.100 | Between 'many hedges' and 'many trees, hedges, and few buildings' |
| 0.001 | Approx. Off sea wind in coastal area |
| 0.003 | Marginally greater than 'Approx. Off sea wind in coastal area' |

# Appendix B

# Information on CTDMPLUS Model

## The CTDMPLUS and CTSCREEN Models

Complex terrain impacts may need to be modeled with more accuracy than that provided by AERMOD. The use of more refined modeling techniques is specifically addressed in EPA's Appendix W[5] modeling guidance, as follows:

> *Since AERMOD treats dispersion in complex terrain, we have merged sections 4 and 5 of appendix W, as proposed in the April 2000 NPR [Notice of Proposed Rulemaking]. And while AERMOD produces acceptable regulatory design concentrations in complex terrain, it does not replace CTDMPLUS for detailed or receptor-oriented complex terrain analysis, as we have made clear in Guideline section 4.2.2. CTDMPLUS remains available for use in complex terrain. [p. 68225]*
>
> *4.2.2 Refined Analytical Techniques*
>
> *d. If the modeling application involves a well defined hill or ridge and a detailed dispersion analysis of the spatial pattern of plume impacts is of interest, CTDMPLUS, listed in Appendix A, is available. CTDMPLUS provides greater resolution of concentrations about the contour of the hill feature than does AERMOD through a different plume-terrain interaction algorithm. [p. 68233]*

CTSCREEN is the same basic model as CTDMPLUS, except that meteorological data are handled internally in a simplified manner. As discussed in the CTSCREEN users guide,[6]

> *Since [CTDMPLUS] accounts for the three-dimensional nature of plume and terrain interaction, it requires detailed terrain and meteorological data that are representative of the modeling domain. Although the terrain data may be readily obtained from topographic maps and digitized for use in the CTDMPLUS, the required meteorological data may not be as readily available.*
>
> *Since the meteorological input requirements of the CTDMPLUS can limit its application, the EPA's Complex-Terrain-Modeling, Technology-Transfer Workgroup developed a methodology to use the advanced techniques of*

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[5] 40 CFR 51 Subpart W, as amended November 9, 2005 at 70 FR 68218, "Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions."

[6] USEPA, EPA-600/8-90-087, "User's Guide to CTDMPLUS: Volume 2. The Screening Mode (CTSCREEN)," October 1990.

*CTDMPLUS in situations where on-site meteorological measurements are limited or unavailable. This approach uses CTDMPLUS in a "screening" mode--actual source and terrain characteristics are modeled with an extensive array of predetermined meteorological conditions.*

*This CTDMPLUS screening mode (CTSCREEN) serves several purposes in regulatory applications. When meteorological data are unavailable, CTSCREEN can be used to obtain conservative (safely above those of refined models), yet realistic, impact estimates for particular sources.*

Therefore, the use of the CTSCREEN version of CTDMPLUS is consistent with EPA guidance.

**Meteorological Data for CTDMPLUS**

The discussion in Section 4 of the protocol addresses meteorological data needed to run AERMOD. As discussed above, an additional model, Complex Terrain Dispersion Model PLUS (CTDMPLUS), may be used in lieu of the model Complex Terrain Screening Model (CTSCREEN) for receptors in the terrain above stack-top height. CTDMPLUS is a USEPA-approved air dispersion model, and is fully supported with user guidance documentation.[7]

CTDMPLUS requires an extensive suite of meteorological data composed of not only wind speed, direction, and temperature, but also horizontal and vertical wind direction standard deviations (sigma theta and sigma phi, respectively), and vertical wind speed standard deviation (sigma w). Many AERMOD-compatible meteorological data sets do not include these non-standard measurements.

It is possible to develop conservative values for the standard deviation parameters sigma theta, sigma phi, and sigma w that are consistent with the available meteorological data, and use them to prepare a meteorological data set that is usable in CTDMPLUS and yields conservative (i.e., high) ground-level concentrations.

If modeling with CTDMPLUS is required, the ISCST3-compatible meteorological data sets for the same four years (1994-1997) that was created for the original modeling analysis for the CC8 project would be used to create the CTDMPLUS-compatible meteorological data set. Because all three of these Gaussian dispersion models—ISCST3, AERMOD, and CTDMPLUS—require upper air data as well as surface data, the upper air data from Oakland would be used as discussed earlier.

The following meteorological parameters are needed for CTDMPLUS and would be taken directly from the AERMET files:

- Observed mixing height, provided as the height of the convective or planetary boundary layer (PBL);

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[7] USEPA. Technology Transfer Network, Support Center for Regulatory Atmospheric Modeling, *http://www.epa.gov/scram001/dispersion_prefrec.htm#ctdmplus*

- Calculated mixing height, provided as the height of the mechanical, or surface, boundary layer (SBL);
- Friction velocity (USTAR);
- Monin-Obukhov length (L); and
- Roughness length ($Z_O$).

The remaining standard deviations (sigma values) are not available from AERMOD and must be obtained from ISCST3-compatible met data files that were developed for the project. Stability classes determined by MPRM[8] or PCRAMMET[9] from the measured Pittsburg meteorological data would be used to select the most conservative values from the following ranges recommended in USEPA's Meteorological Monitoring Guidance document:[10]

| Stability Category | Sigma Phi ($\sigma_\Phi$)/ Regulatory Range (degrees) | Sigma Theta ($\sigma_\theta$)/ Regulatory Range (degrees) |
|---|---|---|
| A | 11.5 | 22.5 |
| B | 10.0 – 11.5 | 17.5 – 22.5 |
| C | 7.8 – 10.0 | 12.5 – 17.5 |
| D | 5.0 – 7.8 | 7.5 – 12.5 |
| E | 2.4 – 5.0 | 3.8 – 7.5 |
| F | < 2.4 | < 3.8 |

The most conservative values (that is, the values that produce the highest modeled impacts) for sigma theta and sigma phi within each range would be determined by conducting a sensitivity analysis for all combinations of stack conditions to be modeled using CTDMPLUS and receptor locations for which CTDMPLUS would be used (that is, receptors above stack height). The sensitivity analysis would use the upper and lower values of each range for each stability category. For example, for stability category D, four combinations would be evaluated as follows:

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[8] The Meteorological Processor for Regulatory Models

[9] EPA meteorological preprocessor

[10] Tables 6-8a and 6-9a in Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-005, US EPA Office of Air and Radiation, Office of Air Quality Planning and Standards, February 2000.

| $\sigma_\Phi$ | $\sigma_\theta$ |
|---|---|
| 5.0 | 7.5 |
| 5.0 | 12.5 |
| 7.8 | 7.5 |
| 7.8 | 12.5 |

For stability category A, maximum values for $\sigma_\Phi$ and $\sigma_\theta$ of 15.0 and 27.0, respectively, would be evaluated. For stability category F, minimum values for $\sigma_\Phi$ and $\sigma_\theta$ of 1.0 and 2.0, respectively, would be evaluated.

Sigma w would be estimated by multiplying sigma-phi (after conversion from degrees to radians) by the horizontal wind speed.

Attachment B-2

Documentation for AERMET Surface Parameters

## AERMET Surface Parameters
## for Northern Sectors

| | Sector 1 | | | | | Sector 2 | | | | | Sector 6 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 321 deg to 53 deg | | | | | 53 deg to 90 deg | | | | | 270 deg to 321 deg | | | | |
| | cultivated farmland | | 50% | | | swamp | | 10% | | | swamp | | 34% | | |
| | swamp | | 10% | | | industrial | | 20% | | | industrial | | 5% | | |
| | industrial | | 3% | | | water | | 70% | | | water | | 61% | | |
| | water | | 37% | | | | | | | | | | | | |
| Month | Suface roughness | Albedo | 2004 Bowen ratio | 2005 Bowen ratio | 2006 Bowen ratio | Suface roughness | Albedo | 2004 Bowen ratio | 2005 Bowen ratio | 2006 Bowen ratio | Suface roughness | Albedo | 2004 Bowen ratio | 2005 Bowen ratio | 2006 Bowen ratio |
| JAN | 0.0400 | 0.1632 | 0.457 | 0.457 | 0.457 | 0.2051 | 0.15 | 0.480 | 0.480 | 0.480 | 0.0671 | 0.1488 | 0.195 | 0.195 | 0.195 |
| FEB | 0.0400 | 0.1632 | 0.457 | 0.457 | 0.457 | 0.2051 | 0.15 | 0.480 | 0.480 | 0.480 | 0.0671 | 0.1488 | 0.195 | 0.195 | 0.195 |
| MAR | 0.0650 | 0.1306 | 0.617 | 0.227 | 0.227 | 0.2201 | 0.124 | 0.490 | 0.280 | 0.280 | 0.1181 | 0.121 | 0.229 | 0.145 | 0.145 |
| APR | 0.0650 | 0.1306 | 0.617 | 0.227 | 0.162 | 0.2201 | 0.124 | 0.490 | 0.280 | 0.180 | 0.1181 | 0.121 | 0.229 | 0.145 | 0.12 |
| MAY | 0.0650 | 0.1306 | 0.617 | 0.227 | 0.617 | 0.2201 | 0.124 | 0.490 | 0.280 | 0.490 | 0.1181 | 0.121 | 0.229 | 0.145 | 0.229 |
| JUN | 0.1500 | 0.1558 | 0.927 | 0.357 | 0.927 | 0.2201 | 0.116 | 0.890 | 0.480 | 0.890 | 0.1181 | 0.1166 | 0.329 | 0.195 | 0.329 |
| JUL | 0.1500 | 0.1558 | 0.927 | 0.927 | 0.927 | 0.2201 | 0.116 | 0.890 | 0.890 | 0.890 | 0.1181 | 0.1166 | 0.329 | 0.329 | 0.329 |
| AUG | 0.1500 | 0.1558 | 0.927 | 0.927 | 0.927 | 0.2201 | 0.116 | 0.890 | 0.890 | 0.890 | 0.1181 | 0.1166 | 0.329 | 0.329 | 0.329 |
| SEP | 0.0750 | 0.1632 | 1.177 | 1.177 | 1.177 | 0.2201 | 0.15 | 0.890 | 0.890 | 0.890 | 0.1181 | 0.1488 | 0.329 | 0.329 | 0.329 |
| OCT | 0.0750 | 0.1632 | 0.277 | 1.177 | 1.177 | 0.2201 | 0.15 | 0.280 | 0.890 | 0.890 | 0.1181 | 0.1488 | 0.145 | 0.329 | 0.329 |
| NOV | 0.0750 | 0.1632 | 0.457 | 1.177 | 1.177 | 0.2201 | 0.15 | 0.480 | 0.890 | 0.890 | 0.1181 | 0.1488 | 0.195 | 0.329 | 0.329 |
| DEC | 0.0400 | 0.1632 | 0.277 | 0.277 | 0.457 | 0.2051 | 0.15 | 0.280 | 0.280 | 0.480 | 0.0671 | 0.1488 | 0.145 | 0.145 | 0.195 |
| ANN | 0.0825 | 0.1532 | 0.6445 | 0.6345 | 0.7241 | 0.2163 | 0.135 | 0.5858 | 0.5842 | 0.6442 | 0.1053 | 0.1338 | 0.2398 | 0.2342 | 0.2544 |

**AERMET Surface Parameters**
**for Southern Sectors**
**Provided by the BAAQMD Staff**

| | Sector 2: 53 deg to 90 deg | | | | | Sector 3: 90 deg to 120 deg | | | | | Sector 4: 120 deg to 270 deg | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Month | Surface roughness | Albedo | 2004 Bowen ratio | 2005 Bowen ratio | 2006 Bowen ratio | Surface roughness | Albedo | 2004 Bowen ratio | 2005 Bowen ratio | 2006 Bowen ratio | Surface roughness | Albedo | 2004 Bowen ratio | 2005 Bowen ratio | 2006 Bowen ratio |
| JANUARY | 0.1514 | 0.1149 | 0.3322 | 0.3322 | 0.3322 | 0.6651 | 0.1542 | 1.1974 | 1.1974 | 1.1974 | 0.6360 | 0.1687 | 1.3117 | 1.3117 | 1.3117 |
| FEBRUARY | 0.1516 | 0.1147 | 0.3304 | 0.3304 | 0.3304 | 0.6672 | 0.1530 | 1.1931 | 1.1931 | 1.1931 | 0.6346 | 0.1595 | 1.2102 | 1.2102 | 1.2102 |
| MARCH | 0.1516 | 0.1147 | 0.5972 | 0.3304 | 0.3304 | 0.6672 | 0.1530 | 2.3833 | 1.1931 | 1.1931 | 0.6346 | 0.1595 | 2.4578 | 1.2102 | 1.2102 |
| APRIL | 0.1517 | 0.1147 | 0.5995 | 0.3313 | 0.2477 | 0.6691 | 0.1536 | 2.3887 | 1.1952 | 0.8083 | 0.6486 | 0.1643 | 2.5700 | 1.2613 | 0.8622 |
| MAY | 0.1517 | 0.1147 | 0.5995 | 0.3313 | 0.5995 | 0.6691 | 0.1536 | 2.3887 | 1.1952 | 2.3887 | 0.6486 | 0.1643 | 2.5700 | 1.2613 | 2.5700 |
| JUNE | 0.1517 | 0.1147 | 0.5995 | 0.3313 | 0.5995 | 0.6691 | 0.1536 | 2.3887 | 1.1952 | 2.3887 | 0.6486 | 0.1643 | 2.5700 | 1.2613 | 2.5700 |
| JULY | 0.1515 | 0.1148 | 0.6006 | 0.6006 | 0.6006 | 0.6671 | 0.1539 | 2.3913 | 2.3913 | 2.3913 | 0.6423 | 0.1665 | 2.6244 | 2.6244 | 2.6244 |
| AUGUST | 0.1515 | 0.1148 | 0.6006 | 0.6006 | 0.6006 | 0.6671 | 0.1539 | 2.3913 | 2.3913 | 2.3913 | 0.6423 | 0.1665 | 2.6244 | 2.6244 | 2.6244 |
| SEPTEMBER | 0.1515 | 0.1148 | 0.6006 | 0.6006 | 0.6006 | 0.6671 | 0.1539 | 2.3913 | 2.3913 | 2.3913 | 0.6423 | 0.1665 | 2.6244 | 2.6244 | 2.6244 |
| OCTOBER | 0.1515 | 0.1148 | 0.2479 | 0.6006 | 0.6006 | 0.6671 | 0.1539 | 0.8088 | 2.3913 | 2.3913 | 0.6423 | 0.1665 | 0.8732 | 2.6244 | 2.6244 |
| NOVEMBER | 0.1514 | 0.1149 | 0.3322 | 0.6018 | 0.6018 | 0.6651 | 0.1542 | 1.1974 | 2.3940 | 2.3940 | 0.6360 | 0.1687 | 1.3117 | 2.6788 | 2.6788 |
| DECEMBER | 0.1514 | 0.1149 | 0.2481 | 0.2481 | 0.3322 | 0.6651 | 0.1542 | 0.8094 | 0.8094 | 1.1974 | 0.6360 | 0.1687 | 0.8843 | 0.8843 | 1.3117 |
| ANNUAL | 0.1515 | 0.1148 | 0.3315 | 0.3315 | 0.3315 | 0.6671 | 0.1538 | 1.1958 | 1.1958 | 1.1958 | 0.6410 | 0.1653 | 1.2738 | 1.2738 | 1.2738 |

# AERMET Land Use Parameters

Climatology for Bowen Ratio (from BAAQMD)

| | | 2004 | 2005 | 2006 |
|---|---|---|---|---|
| Winter | JAN | average | average | average |
| | FEB | average | average | average |
| Spring | MAR | dry | average | average |
| | APR | dry | average | wet |
| | MAY | dry | average | dry |
| Summer | JUN | dry | average | dry |
| | JUL | dry | dry | dry |
| | AUG | dry | dry | dry |
| Fall | SEP | dry | dry | dry |
| | OCT | wet | dry | dry |
| | NOV | average | dry | dry |
| Winter | DEC | wet | wet | average |
| | ANN | average | average | average |

ALBEDO OF GROUND COVERS BY LAND-USE AND SEASON

| Land-Use | Spring | Summer | Autumn | Winter in this project* | Winter |
|---|---|---|---|---|---|
| Water (fresh and sea) | 0.12 | 0.1 | 0.14 | 0.14 | 0.2 |
| Deciduous Forest | 0.12 | 0.12 | 0.12 | 0.12 | 0.5 |
| Coniferous Forest | 0.12 | 0.12 | 0.12 | 0.12 | 0.35 |
| Swamp | 0.12 | 0.14 | 0.16 | 0.16 | 0.3 |
| Cultivated Land | 0.14 | 0.2 | 0.18 | 0.18 | 0.6 |
| Grassland | 0.18 | 0.18 | 0.2 | 0.2 | 0.6 |
| Urban | 0.14 | 0.16 | 0.18 | 0.18 | 0.35 |
| Desert Shrubland | 0.3 | 0.28 | 0.28 | 0.28 | 0.45 |

* The winter Albedo in the project area is similar to that of autumn because there is no ice season.

# AERMET Land Use Parameters

DAYTIME BOWEN RATIO BY LAND USE AND SEASON
DRY CONDITIONS

| Land-Use | Spring | Summer | Autumn | Winter in this project* | Winter |
|---|---|---|---|---|---|
| Water (fresh and sea) | 0.1 | 0.1 | 0.1 | 0.1 | 2 |
| Deciduous Forest | 1.5 | 0.6 | 2 | 2 | 2 |
| Coniferous Forest | 1.5 | 0.6 | 1.5 | 1.5 | 2 |
| Swamp | 0.2 | 0.2 | 0.2 | 0.2 | 2 |
| Cultivated Land | 1 | 1.5 | 2 | 2 | 2 |
| Grassland | 1 | 2 | 2 | 2 | 2 |
| Urban | 2 | 4 | 4 | 4 | 2 |
| Desert Shrubland | 5 | 6 | 10 | 10 | 10 |

DAYTIME BOWEN RATIO BY LAND USE AND SEASON
AVERAGE CONDITIONS

| Land-Use | Spring | Summer | Autumn | Winter in this project* | Winter |
|---|---|---|---|---|---|
| Water (fresh and sea) | 0.1 | 0.1 | 0.1 | 0.1 | 1.5 |
| Deciduous Forest | 0.7 | 0.3 | 1 | 1 | 1.5 |
| Coniferous Forest | 0.7 | 0.3 | 0.8 | 0.8 | 1.5 |
| Swamp | 0.1 | 0.1 | 0.1 | 0.1 | 1.5 |
| Cultivated Land | 0.3 | 0.5 | 0.7 | 0.7 | 1.5 |
| Grassland | 0.4 | 0.8 | 1 | 1 | 1.5 |
| Urban | 1 | 2 | 2 | 2 | 1.5 |
| Desert Shrubland | 3 | 4 | 6 | 6 | 6 |

DAYTIME BOWEN RATIO BY LAND USE AND SEASON
WET CONDITIONS

| Land-Use | Spring | Summer | Autumn | Winter in this project* | Winter |
|---|---|---|---|---|---|
| Water (fresh and sea) | 0.1 | 0.1 | 0.1 | 0.1 | 0.3 |
| Deciduous Forest | 0.3 | 0.2 | 0.4 | 0.4 | 0.5 |
| Coniferous Forest | 0.3 | 0.2 | 0.3 | 0.3 | 0.3 |
| Swamp | 0.1 | 0.1 | 0.1 | 0.1 | 0.5 |
| Cultivated Land | 0.2 | 0.3 | 0.4 | 0.4 | 0.5 |
| Grassland | 0.3 | 0.4 | 0.5 | 0.5 | 0.5 |
| Urban | 0.5 | 1 | 1 | 1 | 0.5 |
| Desert Shrubland | 1 | 1.5 | 2 | 2 | 2 |

* The winter Bowen ratio in the project area are similar to that of autumn, because of the unique seasonal characteristics in Bay Area.

SURFACE ROUGHNESS LENGTH, IN METERS, BY LAND-USE AND SEASON

| Land-Use | Spring | Summer | Autumn | Winter |
|---|---|---|---|---|
| Water (fresh and sea) | 0.0001 | 0.0001 | 0.0001 | 0.0001 |
| Deciduous Forest | 1 | 1.3 | 0.8 | 0.5 |
| Coniferous Forest | 1.3 | 1.3 | 1.3 | 1.3 |
| Swamp | 0.2 | 0.2 | 0.2 | 0.05 |
| Cultivated Land | 0.03 | 0.2 | 0.05 | 0.01 |
| Grassland | 0.05 | 0.1 | 0.01 | 0.001 |
| Urban | 1 | 1 | 1 | 1 |
| Desert Shrubland | 0.3 | 0.3 | 0.3 | 0.15 |

** All values extracted from "USER'S GUIDE FOR THE AERMOD METEOROLOGICAL PREPROCESSOR (AERMET)"

Appendix C

Screening Health Risk Assessment

## Screening Health Risk Assessment

The screening level health risk assessment has been prepared using CARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.2a, August 26, 2005) and associated guidance in the OEHHA's *Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* (August 2003). The HARP model was used to assess cancer risk as well as chronic and acute risk impacts. The following paragraphs describe the procedures used to prepare this risk assessment.

## Modeling Inputs

The risk assessment module of the HARP model was run using unit ground level impacts to obtain derived cancer risks for each toxic chemical of interest.[1] Cancer risks were obtained for the derived (adjusted) method and the derived (OEHHA) method (for worker exposure) options. The HARP model output was cancer risk by pollutant and route for each type of analysis, based on an exposure of 1.0 $\mu g/m^3$. Individual cancer risks are expressed in units of risk per $\mu g/m^3$ of exposure. To calculate the weighted risk for each source, the annual average emission rate in g/s for each pollutant was multiplied by the individual cancer risk for that pollutant in $(\mu g/m^3)^{-1}$. The resulting weighted cancer risks for each pollutant were then summed for the source. An identical approach was used to determine the acute and chronic health impacts associated with the proposed project. Details of the calculations of risk "rates" for modeling are shown in Tables C-1 through C-4.

## Risk Analysis Method

The results of the turbine screening analysis (see Appendix B, Table B-3) were used to determine the worst-case full load operating conditions for modeling for the annual and 1-hour averaging periods, used in determining cancer risk and chronic HHI, and acute HHI, respectively. The total weighted risk "rate" for each source was used in place of emission rates in the modeling analysis. The weighted risk "rates" used for the HRA modeling are summarized in Table C-5. The calculated value was then total cancer risk at each receptor. As discussed in Part III of the application, the screening analysis for the criteria pollutant modeling analysis was performed using the AERMOD model, the 2004 through 2006 Contra Costa meteorological data, specific receptor grids, and the stack parameters for eight operating cases. The exhaust characteristics for the highest full-load 1-hour and annual average unit impacts from the screening analysis, Case 5, was used to model cancer risks from the turbines for the proposed project.

As shown in Table 13, the cancer risk from the project is slightly above 1 in one million, due to the Diesel particulate matter emissions from the fire pump engine. However, since the fire pump engine particulate emission limit meets Toxics BACT levels and the cancer risk is well below 10 in one million, the project can be approved. In addition, the area where the cancer risk exceeds 1 in one million barely crosses the facility fenceline so it is extremely unlikely that anyone will experience the maximum modeled risk. Finally, the acute and chronic health hazard indices are well below the significance level of one.

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[1] Procedure is described in Part B of Topic 8 of the HARP How-To Guides: How to Perform Health Analyses Using a Ground Level Concentration.

The analysis of potential cancer risk described in this section employs extremely conservative methods and assumptions, as follows:

- The analysis includes representative weather data over 3 years to ensure that the least favorable conditions producing the highest ground-level concentration of power plant emissions are included. The analysis then assumes that these worst-case weather conditions, which in reality occurred only once in 3 years, will occur every year for 70 years.
- The analysis assumes that a sensitive individual is at the location of the highest ground-level concentration of power plant emissions continuously over the entire 70-year period. In reality, people rarely live in their homes for 70 years, and even if they do, they leave their homes to attend school, go to work, go shopping, and so on. Further, as described above, the highest ground-level impact occurs near the fenceline of the facility, where there are no residences or other sensitive receptors.

The point of using these unrealistic assumptions is to consciously overstate the potential impacts. No one will experience exposures as great as those assumed for this analysis. By determining that even this highly overstated exposure will not be significant, there is a high degree of confidence that the much lower exposures that actual persons will experience will not result in a significant increase in cancer risk. In short, the analysis ensures that there will not be significant public health impacts at any location, under any weather condition, under any operating condition.

**Table C-1**
**Gateway Generating Station**
**Calculation of Modeling Inputs for CTG/HRSG Cancer Risk Assessment**

| | | Derived (Adjusted) Method | | Worker Exp: Derived (OEHHA) Method | |
|---|---|---|---|---|---|
| Compound | Annual Average Emissions Per Engine g/s | Unit Risk (per ug/m3) | Cancer Risk Model Input (per ug/m3 per g/s) | Unit Risk (per ug/m3) | Cancer Risk Model Input (per ug/m3 per g/s) |
| Ammonia | 3.37E+00 | 0 | 0 | 0 | 0 |
| Propylene | 1.91E-01 | 0 | 0 | 0 | 0 |
| Acetaldehyde | 1.01E-02 | 2.90E-06 | 2.93E-02 | 5.72E-07 | 5.79E-03 |
| Acrolein | 9.15E-04 | 0 | 0 | 0 | 0 |
| Benzene | 8.26E-04 | 2.90E-05 | 2.40E-02 | 5.72E-06 | 4.72E-03 |
| 1,3-Butadiene | 1.09E-04 | 1.74E-04 | 1.89E-02 | 3.43E-05 | 3.73E-03 |
| Ethylbenzene | 8.09E-03 | 0 | 0 | 0 | 0 |
| Formaldehyde | 9.10E-02 | 6.08E-06 | 5.53E-01 | 1.20E-06 | 1.09E-01 |
| Hexane | 6.42E-02 | 0 | 0 | 0 | 0 |
| Naphthalene | 4.12E-04 | 3.48E-05 | 1.43E-02 | 6.86E-06 | 2.82E-03 |
| PAHs (Note 1) | 1.13E-05 | 1.65E-02 | 1.87E-01 | 1.47E-02 | 1.66E-01 |
| Propylene Oxide | 7.39E-03 | 3.76E-06 | 2.78E-02 | 7.43E-07 | 5.49E-03 |
| Toluene | 3.30E-02 | 0 | 0 | 0 | 0 |
| Xylene | 1.62E-02 | 0 | 0 | 0 | 0 |
| | | | 8.55E-01 per ug/m3 | | 2.98E-01 per ug/m3 |

Notes:
(1) Emission rates for individual PAHs weighted by risk relative to B(a)P. See Table A-6.

**Table C-2**
**Gateway Generating Station**
**Calculation of Modeling Inputs and HHIs for CTG Acute and Chronic Risk Assessment**

| Compound | Acute Health Impacts | | | Chronic Health Impacts | | |
|---|---|---|---|---|---|---|
| | Max Hourly Emissions Per Engine g/s | HARP Acute HI (per ug/m3) | Acute HHI Model Input (per ug/m3 per g/s) | Annual Average Emissions, g/s | HARP Chronic HI (per ug/m3) | Chronic HHI Model Input (per ug/m3 per g/s) |
| Ammonia | 3.54E+00 | 3.13E-04 | 1.11E-03 | 3.367 | 5.00E-03 | 1.68E-02 |
| Propylene | 2.01E-01 | -- | -- | 0.191 | 3.33E-04 | 6.37E-05 |
| Acetaldehyde | 1.06E-02 | -- | -- | 1.01E-02 | 1.11E-01 | 1.12E-03 |
| Acrolein | 9.62E-04 | 5.26E+00 | 5.06E-03 | 9.15E-04 | 1.67E+01 | 1.53E-02 |
| Benzene | 8.68E-04 | 7.69E-04 | 6.68E-07 | 8.26E-04 | 1.67E-02 | 1.38E-05 |
| 1,3-Butadiene | 1.14E-04 | -- | -- | 1.09E-04 | 5.00E-02 | -- |
| Ethylbenzene | 8.50E-03 | -- | -- | 8.09E-03 | 5.00E-04 | 4.04E-06 |
| Formaldehyde | 9.57E-02 | 1.06E-02 | 1.01E-03 | 9.10E-02 | 3.33E-01 | 3.03E-02 |
| Hexane | 6.75E-02 | -- | -- | 6.42E-02 | 1.43E-04 | 9.19E-06 |
| Naphthalene | 4.33E-04 | -- | -- | 4.12E-04 | 1.11E-01 | 4.57E-05 |
| PAHs | 1.19E-05 | -- | -- | 1.13E-05 | -- | -- |
| Propylene Oxide | 7.77E-03 | 3.23E-04 | 2.51E-06 | 7.39E-03 | 3.33E-02 | 2.46E-04 |
| Toluene | 3.47E-02 | 2.70E-05 | 9.36E-07 | 3.30E-02 | 3.33E-03 | 1.10E-04 |
| Xylene | 1.70E-02 | 4.55E-05 | 7.75E-07 | 1.62E-02 | 1.43E-03 | 2.32E-05 |
| | | Total = | 7.19E-03 | | Total = | 6.41E-02 |

**Table C-3**
**Gateway Generating Station**
**Cancer Risk Assessment Modeling Inputs for Other Equipment**

**Dewpoint Heater**

| | | Derived (Adjusted) Method | | Worker Exp: Derived (OEHHA) Method | |
|---|---|---|---|---|---|
| Compound | Annual Average Emissions | Unit Risk (per ug/m3) | Cancer Risk Model Input (per ug/m3 | Unit Risk (per ug/m3) | Cancer Risk Model Input (per ug/m3 |
| Ammonia | -- | 0 | 0 | 0 | 0 |
| Propylene | 5.90E-04 | 0 | 0 | 0 | 0 |
| Acetaldehyde | 3.48E-06 | 2.90E-06 | 1.01E-05 | 5.72E-07 | 1.99E-06 |
| Acrolein | 2.18E-06 | 0 | 0 | 0 | 0 |
| Benzene | 6.47E-06 | 2.90E-05 | 1.88E-04 | 5.72E-06 | 3.70E-05 |
| 1,3-Butadiene | -- | 1.74E-04 | 0.00E+00 | 3.43E-05 | 0.00E+00 |
| Ethylbenzene | 7.68E-06 | 0 | 0 | 0 | 0 |
| Formaldehyde | 1.37E-05 | 6.08E-06 | 8.36E-05 | 1.20E-06 | 1.65E-05 |
| Hexane | 5.09E-06 | 0 | 0 | 0 | 0 |
| Naphthalene | 2.43E-07 | 3.48E-05 | 8.44E-06 | 6.86E-06 | 1.66E-06 |
| PAHs (Note 1) | 8.09E-08 | 1.65E-02 | 1.33E-03 | 1.47E-02 | 1.19E-03 |
| Propylene Oxide | -- | 3.76E-06 | 0 | 7.43E-07 | 0 |
| Toluene | 2.96E-05 | 0 | 0 | 0 | 0 |
| Xylene | 2.20E-05 | 0 | 0 | 0 | 0 |
| | | | 1.62E-03 per ug/m3 | | 1.25E-03 per ug/m3 |

**Fire Pump Engine**

| | | Derived (Adjusted) Method | | Worker Exposure: Derived (OEHHA) Method | |
|---|---|---|---|---|---|
| Compound | Annual Average Emissions, g/s | Unit Risk (per ug/m3) | Cancer Risk Model Input (per ug/m3 per g/s) | Unit Risk (per ug/m3) | Cancer Risk Model Input (per ug/m3 per g/s) |
| Diesel Exhaust Particulate | 5.71E-05 | 3.19E-04 | 1.82E-02 per ug/m3 | 6.29E-05 | 3.59E-03 per ug/m3 |

**Table C-4**
**Gateway Generating Station**
**Calculation of Modeling Inputs and HHIs for Other Equipment Acute and Chronic Risk Assessment**

**Dewpoint Heater**

| Compound | Acute Health Impacts | | | Chronic Health Impacts | | |
|---|---|---|---|---|---|---|
| | Max Hourly Emissions, g/s | HARP Acute HI (per ug/m3) | Acute HHI Model Input (per ug/m3 per g/s) | Annual Average Emissions, g/s | HARP Chronic HI (per ug/m3) | Chronic HHI Model Input (per ug/m3 per g/s) |
| Propylene | 5.90E-04 | -- | -- | 5.90E-04 | 3.33E-04 | 1.97E-07 |
| Acetaldehyde | 3.48E-06 | -- | -- | 3.48E-06 | 1.11E-01 | 3.86E-07 |
| Acrolein | 2.18E-06 | 5.26E+00 | 1.15E-05 | 2.18E-06 | 1.67E+01 | 3.65E-05 |
| Benzene | 6.47E-06 | 7.69E-04 | 4.97E-09 | 6.47E-06 | 1.67E-02 | 1.08E-07 |
| 1,3-Butadiene | -- | -- | -- | -- | 5.00E-02 | -- |
| Ethylbenzene | 7.68E-06 | -- | -- | 7.68E-06 | 5.00E-04 | 3.84E-09 |
| Formaldehyde | 1.37E-05 | 1.06E-02 | 1.46E-07 | 1.37E-05 | 3.33E-01 | 4.58E-06 |
| Hexane | 5.09E-06 | -- | -- | 5.09E-06 | 1.43E-04 | 7.29E-10 |
| Naphthalene | 2.43E-07 | -- | -- | 2.43E-07 | 1.11E-01 | 2.69E-08 |
| PAHs | 8.09E-08 | -- | -- | 8.09E-08 | -- | -- |
| Propylene Oxide | -- | 3.23E-04 | -- | -- | 3.33E-02 | -- |
| Toluene | 2.96E-05 | 2.70E-05 | 7.99E-10 | 2.96E-05 | 3.33E-03 | 9.86E-08 |
| Xylene | 2.20E-05 | 4.55E-05 | 1.00E-09 | 2.20E-05 | 1.43E-03 | 3.15E-08 |
| | | Total = | 1.16E-05 | | Total = | 4.19E-05 |

**Fire Pump Engine**

| Compound | Max Hourly Emissions for Em Gen. g/s | HARP Acute HI (per ug/m3) | Acute HHI Model Input (per ug/m3 per g/s) | Annual Average Emissions, g/s | HARP Chronic HI (per ug/m3) | Chronic HHI Model Input (per ug/m3 per g/s) |
|---|---|---|---|---|---|---|
| Particulate Em from Diesel-Fueled Engines | 1.00E-02 | n/a | n/a | 5.71E-05 | 2.00E-01 | 1.14E-05 |
| | | | | | Total = | 1.14E-05 |

**Table C-5**
**Gateway Generating Station**
**Summary of Modeling Input Values for Screening HRA**

| Unit | Derived (Adjusted) Method Cancer Risk (Res) | Derived (OEHHA) Method Cancer Risk (Worker) | Chronic HHI Model Input (per ug/m3) | Acute HHI Model Input (per ug/m3) |
|---|---|---|---|---|
| CTGs (each) | 8.547E-01 | 2.983E-01 | 6.407E-02 | 7.187E-03 |
| Dewpoint Heater | 1.624E-03 | 1.246E-03 | 4.189E-05 | 1.164E-05 |
| Diesel fire pump engine | 1.821E-02 | 3.590E-03 | 1.142E-05 | - |

All modeling input values are in units of per ug/m3

| **Stack Parameters** | | | | |
|---|---|---|---|---|
| | Stack Diam (m) | Stack Ht (m) | Exhaust Temp (deg K) | Exhaust Velocity (m/s) |
| CTGs (each) | 5.108 | 59.436 | 355.222 | 19.923 |
| Dewpoint Heater | 0.203 | 4.715 | 422.039 | 28.719 |
| Diesel fire pump engine | 0.154 | 3.251 | 683.150 | 44.058 |

Appendix D

Revised Permit Conditions

## Gateway Generating Station Permit Conditions

Definitions:

1-hour period: Any continuous 60-minute period beginning on the hour.

Calendar Day: Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.

Year: Any consecutive twelve-month period of time

Heat Input: All heat inputs refer to the heat input at the higher heating value fuel, in Btu/scf.

Rolling 3-hour period: Any three-hour period that begins on the hour and does not include start-up or shutdown periods.

Firing Hours: Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments.

MM Btu: million British thermal units

Gas Turbine Start-up Mode: The lesser of the first 360 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d).

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Gas Turbine Shutdown Mode: The lesser of the 60 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(a) through 20(d) until termination of fuel flow to the Gas Turbine.

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Specified PAHs: The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.

Benzo[a]anthracene

Benzo[b]fluoranthene

Benzo[k]fluoranthene

Benzo[a]pyrene

Dibenzo[a,h]anthracene

Indeno[1,2,3-cd]pyrene

Corrected Concentration: The concentration of any pollutant (generally NOx, CO, or NH3) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% O2 by volume on a dry basis.

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the GGS construction contractor to insure safe and reliable steady state

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operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.

Commissioning Period: The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing and is available for commercial operation.

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Combustor Tuning Activities: All testing, adjustment, tuning, and calibration activities recommended by the gas turbine manufacturer or an independent qualified contractor to insure safe and reliable steady state operation of the gas turbines following replacement of the combustor. This includes, but is not limited to, adjusting the amount of fuel distributed between the combustion turbine's staged fuel systems to simultaneously minimize NOx and CO production while minimizing combustor dynamics and ensuring combustor stability.

Combustor Tuning Period: The period, not to exceed 360 minutes, during which gas turbine combustor tuning activities are taking place.

Precursor Organic Compounds (POCs): Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate

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CEC CPM: California Energy Commission Compliance Program Manager.

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CCPP Unit#8: Contra Costa Power Plant Unit 8

GGS: Gateway Generating Station

Conditions for the Commissioning Period

1. The owner/operator of the GGS shall minimize emissions of carbon monoxide and nitrogen oxides from S-41 and S-43 Gas Turbines and S-42 and S-44 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period. Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 47 shall apply after the commissioning period has ended.

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2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-41 & S-43 Gas Turbine combustors and S-42 & S-44 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-11 and A-13 SCR Systems and A-12 and A-14 CO Oxidation Catalyst Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-41 & S-43 Gas Turbines and S-42 & S-44 Heat Recovery Steam Generators.

4. Coincident with the as designed operation of A-11 & A-13 SCR Systems, pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall comply with the NOx and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the GGS shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas

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Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired dewpoint heater. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NOx combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

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6. During the commissioning period, the owner/operator of the GGS shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

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- firing hours for each gas turbine and each HRSG
- fuel flow rates to each train
- stack gas nitrogen oxide emission concentrations at P-11 and P-12
- stack gas carbon monoxide emission concentrations P-11 and P-12
- stack gas carbon dioxide or oxygen concentrations P-11 and P-12

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44). The owner/operator shall use District-approved methods to calculate heat input rates, NOx mass emission rates, carbon monoxide mass emission rates, and NOx and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous emission monitors specified in condition 6 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44). After first firing of the turbines, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NOx emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-41 Gas Turbine and S-42 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-11 SCR System and/or A-12 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-41 Gas Turbine and S-42 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

9. The total number of firing hours of S-43 Gas Turbine and S-44 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-13 SCR System and/or A-14 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-43 Gas Turbine and S-44 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the

District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

11. Combined pollutant mass emissions from the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-41 & S-43).

| | | |
|---|---|---|
| NOx (as NO2) | 8,400 pounds/calendar day | 400 pounds/hour |
| CO | 40,000 pounds/calendar day | 4,000 pounds/hour |
| POC(as CH4) | 1,600 pounds/calendar day | |
| PM10 | 432 pounds/calendar day | |
| SO2 | 297 pounds/calendar day | |

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12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 21. The source test shall determine NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-41 & S-43) and the Heat Recovery Steam Generators (HRSGs; S-42 & S-44)

13. The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on natural gas. (BACT for SO2 and PM10)

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,094.4 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for NOx)

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15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 49,950 MM Btu per calendar day. (PSD for PM10)

16. The combined cumulative heat input rate for the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall not exceed 34,900,000 MM Btu per year. (Offsets)

17. The HRSG duct burners (S-42 and S-44) shall not be fired unless its associated Gas Turbine (S-41 and S-43, respectively) is in operation. (BACT for NOx)

18. Except as provided in Condition No. 8, S-41 Gas Turbine and S-42 HRSG shall be abated by the properly operated and properly maintained A-11 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-11 catalyst bed has reached minimum operating temperature. (BACT for NOx)

19. Except as provided in Condition No. 9, S-43 Gas Turbine and S-44 HRSG shall be abated by the properly operated and properly maintained A-13 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-13 catalyst bed has reached minimum operating temperature. (BACT for NOx)

20. The Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S- 44) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

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(a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO2) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed 15.2 pounds per hour or 0.0072 lb./MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO2) at P-12 (the combined exhaust point for the S-43 Gas Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed 15.2 pounds per hour or 0.0072 lb./MM Btu (HHV) of natural gas fired. (PSD for NOx)

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(b) The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O2, averaged over any 1-hour period. (BACT for NOx)

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(c) Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed 0.0088 lb./MM Btu (HHV) of natural gas fired or 18.5 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

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(d) The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed 4 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. (BACT for CO)

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(e) Ammonia (NH3) emission concentrations at P-11 and P-12 each shall not exceed 10 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (TRMP for NH3)

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(f) Precursor organic compound (POC) mass emissions (as CH4) at P-11 and P-12 each shall not exceed 5.3 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)

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(g) Sulfur dioxide (SO2) mass emissions at P-11 and P-12 each shall not exceed 5.92 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)

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(h) Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or 0.0095 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed 12 pounds per hour or 0.0065 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

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(i) Compliance with the hourly NOx emission limitations specified in condition 20(a) and 20(b) shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the owner/operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv, dry @ 15% O2. Examples of transient load conditions include, but are not limited to the following:

(1) Initiation/shutdown of combustion turbine inlet air cooling

(2) Rapid combustion turbine load changes

(3) Initiation/shutdown of HRSG duct burners

The maximum 1-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmv, dry @ 15% O2. All emissions during short-term excursions shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-41 and S-43) during a start- up or a shutdown or during a combustor tuning period shall not exceed the limits established below. (PSD)

| | Start-Up or Combustor Tuning Period (lb./period) | Startup/Shutdown (lb./hr) |
|---|---|---|
| Oxides of Nitrogen (as NO2) | 600 | 160 |
| Carbon Monoxide (CO) | 5,400 | 900 |
| Precursor Organic Compounds (as CH4) | 96 | 16 |

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22. The Gas Turbines (S-41 and S-43) shall not be in start-up mode simultaneously. (PSD)

23. Total combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44), including emissions generated during Gas Turbine start-ups, shutdowns and combustor tuning periods shall not exceed the following limits during any calendar day:

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(a) 1,994 pounds of NOx (as NO2) per day (CEQA)

(b) 11,470 pounds of CO per day (PSD)

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(c) 468 pounds of POC (as CH4) per day (CEQA)

(d) 577 pounds of PM10 per day (PSD)

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(e) 297 pounds of SO2 per day (BACT)

24. Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44) and the Dewpoint Heater (S-45) and the Diesel Fire Pump Engine (S-48), including emissions generated during gas turbine start-ups, shutdowns and combustor tuning periods shall not exceed the following limits during any consecutive twelve-month period:

(a) 174.3 tons of NOx (as NO2) per year (Offsets, PSD)

(b) 555.4 tons of CO per year (Cumulative Increase)

(c) 46.6 tons of POC (as CH4) per year (Offsets)

(d) 101.7 tons of PM10 per year (Offsets, PSD)

(e) 37.0 tons of SO2 per year (Cumulative Increase)

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25. Toxic and HAP Emission Limits

25.1. The maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limits:

12,656 pounds of formaldehyde per year

115 pounds of benzene per year

6.2 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

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unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 10.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

25.2. The maximum projected annual Hazardous Air Pollutant (HAP) emissions from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limit:

20,000 pounds of hexane per year (US-CAA, Section 112(g))

Conformance with this limit shall be verified by the source testing in condition 32.

26. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 23(a), 23(b), 24(a), and 24(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up, Shutdown and Combustor Tuning periods) for all of the following parameters:

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(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

(b) Carbon Dioxide (CO2) or Oxygen (O2) concentrations, Nitrogen Oxides (NOx) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.

(c) Ammonia injection rate at A-11 and A-13 SCR Systems

(d) Steam injection rate at S-41 & S-43 Gas Turbine Combustors

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and average hourly pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(e) Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

(f) Corrected NOx concentrations, NOx mass emissions (as NO2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.

Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and 26(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-41, S-42, S-43, and S-44) combined.

(i) the average NOx mass emissions (as NO2), CO mass emissions, and corrected NOx and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(j) on an hourly basis, the cumulative total NOx mass emissions (as NO2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.

(k) For each calendar day, the average hourly Heat Input Rates, Corrected NOx emission concentrations, NOx mass emissions (as NO2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

(l) on a daily basis, the cumulative total NOx mass emissions (as NO2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c) through 23(e), and 24(c) through 24(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM10) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO2) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 26, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM10, and SO2 emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-41, S-42, S-43, and S-44) combined.

(b) on a daily basis, the 365 day rolling average cumulative total POC, PM10, and SO2 mass emissions, for all four sources (S-41, S-42, S-43, and S-44) combined.

(Offsets, PSD, Cumulative Increase)

28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of Formaldehyde, Benzene, and Specified PAHs. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 34,900,000 MM Btu/year and the highest emission factor (pounds of pollutant per MM Btu of Heat Input) determined by any source test of the S-41 & S-43 Gas Turbines and/or S-42 & S-44 Heat Recovery Steam Generators. If this calculation method results in an unrealistic mass emission rate (the highest emission factor occurs at a low firing rate) the applicant may use an alternate calculation, subject to District approval. (TRMP)

29. Within 60 days of start-up of the GGS, the owner/operator shall conduct a District-approved source est on exhaust point P-11 or P-12 to determine the corrected ammonia (NH3) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding NH3 emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NOx emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

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30. Within 60 days of start-up of the GGS and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM10) emissions including condensable particulate matter. (BACT, offsets)

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**Deleted:** (including steam injection power augmentation mode)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM10 emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used

to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 60 days of start-up of the GGS and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 28 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

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| | | |
|---|---|---|
| Benzene | less than or equal | 26.8 pounds/year |
| Formaldehyde | less than or equal | 132 pounds/year |
| Specified PAHs | less than or equal | 0.18 pounds/year |

(TRMP)

33. The owner/operator of the GGS shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

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34. The owner/operator of the GGS shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

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35. The owner/operator of the GGS shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

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36. The stack height of emission points P-11 and P-12 shall each be at least 195 feet above grade level at the stack base. (PSD, TRMP)

37. The Owner/Operator of GGS shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Regulation 1-501)

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38. Within 180 days of the issuance of the Authority to Construct for the GGS, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 26, 29, 30 and 32. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

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39. Prior to the issuance of the BAAQMD Authority to Construct for the GGS, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of

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200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and 101.7 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

40. Prior to the start of construction of the GGS, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and 101.7 tons of Particulate Matter less than 10 microns. (Offsets)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of the GGS shall submit an application to the BAAQMD for a significant revision to the Major Facility Review Permit prior to commencing operation. (Regulation 2-6-404.3)

42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the CCPP Unit 8 shall not operate either of the gas turbines until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Regulation 2, Rule 7)

43. The GGS shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

44. The owner/operator shall take quarterly samples of the natural gas combusted at the GGS. The samples shall be analyzed for sulfur content using District- approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. Sulfur content of each individual sample shall be no more than 1.0 grains/100 scf. Average sulfur content of four quarterly samples shall be no more than 0.75 grains/100 scf. (cumulative increase)

45. [deleted]46. [deleted]~~o~~47. The Dewpoint Heater (S-45) shall not be fired more than 156 MMBtu/day. (BACT)

**Conditions for S-48 Emergency Fire Pump Engine**

48. Operation of S-48 for reliability-related activities is limited to 50 hours per year. (Stationary Diesel Engine ATCM)

49. The owner/operator shall operate engine S-48 only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. (Stationary Diesel Engine ATCM)

50. The owner/operator shall operate engine S-48 only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. (Stationary Diesel Engine ATCM)

51. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 36 months from the date of entry. Log entries shall be

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**Deleted:** The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 5,666 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

**Deleted:** The owner/operator shall perform a visual inspection

**Deleted:** f the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the CCPP Unit 8, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. The CEC CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the PM10 emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD) ¶

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retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. (Stationary Diesel Engine ATCM)

a. Hours of operation of S-48 for reliability-related activities (maintenance and testing).

b. Hours of operation of S-48 for emission testing to show compliance with emission limits.

c. Hours of emergency operation of S-48.

d. For each emergency, the nature of the emergency condition.

e. Fuel usage for S-48.

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street, San Francisco, CA 94109
Engineering Division (415) 749-4990
www.baaqmd.gov fax (415) 749-5030

**Form P-101B**
Authority to Construct/
Permit to Operate

| | | |
|---|---|---|
| | | |

## 1. Application Information

BAAQMD Plant No. 18143 Company Name Gateway Generating Station

Equipment/Project Description two natural gas-fired combustion turbine generators with duct firing and aux. eqt.

## 2. Plant Information

*If you have not previously been assigned a Plant Number by the District or if you want to update any plant data that you have previously supplied to the District, please complete this section.*

Equipment Location 3225 Wilbur Avenue

City Antioch, CA Zip Code 94509

Mail Address 77 Beale St, Mail Stop B24A

City San Francisco State CA Zip Code 94105

Plant Contact Angel Espiritu Title Sr. Environmental Specialist

Telephone (925) 459-7212 Fax (925) 459-7223 Email ABE4@pge.com

NAICS (North American Industry Classification System) see www.census.gov/epcd/naics02/naico602.htm 221112

## 3. Proximity to a School (K-12)

The sources in this permit application (*check one*) ☐ Are ☑ Are not within 1,000 ft of the outer boundary of the nearest school.

## 4. Application Contact Information

*All correspondence from the District regarding this application will be sent to the plant contact unless you wish to designate a different contact for this application.*

Application Contact Tom Allen Title Project Manager

Mail Address 3225 Wilbur Avenue

City Antioch State CA Zip Code 94509

Telephone (925) 459-7200 Fax ( ) Email HTA1@pge.com

## 5. Additional Information

*The following additional information is required for all permit applications and should be included with your submittal. Failure to provide this information may delay the review of your application. Please indicate that each item has been addressed by checking the box. Contact the Engineering Division if you need assistance.*

- ☐ If a new Plant, a local street map showing the location of your business
- ☑ A facility map, drawn roughly to scale, that locates the equipment and its emission points
- ☑ Completed data form(s) and a pollutant flow diagram for each piece of equipment. (See www.baaqmd.gov/pmt/forms/ )
- ☑ Project/equipment description, manufacturer's data
- ☑ Discussion and/or calculations of the emissions of air pollutants from the equipment

## 6. Trade Secrets

*Under the California Public Records Act, all information in your permit application will be considered a matter of public record and may be disclosed to a third party. If you wish to keep certain items separate as specified in Regulation 2, Rule 1, Section 202.7, please complete the following steps.*

- ☐ Each page containing trade secret information must be labeled "trade secret" with the trade secret information clearly marked.
- ☐ A second copy, with trade secret information blanked out, marked "public copy" must be provided.
- ☐ For each item asserted to be trade secret, you must provide a statement which provides the basis for your claim.

**7. Small Business Certification** *You are entitled to a reduced permit fee if you qualify as a small business as defined in Regulation 3. In order to qualify, you must certify that your business meets all of the following criteria.*

- ☐ The business does not employ more than 10 persons and its gross annual income does not exceed $600,000.
- ☐ And the business is not an affiliate of a non-small business. (Note: a non-small business employs more than 10 persons and/or its gross income exceeds $600,000.)

**8. Accelerated Permitting** *The Accelerated Permitting Program entitles you to install and operate qualifying sources of air pollution and abatement equipment* ***without waiting for the District to issue a Permit to Operate.*** *To participate in this program you must certify that your project will meet all of the following criteria. Please acknowledge each item by checking each box.*

- ☐ Uncontrolled emissions of any single pollutant are each less than 10 lb/highest day, or the equipment has been precertified by the BAAQMD.
- ☐ Emissions of toxic compounds do not exceed the trigger levels identified in Table 2-5-1 (see Regulation 2, Rule 5).
- ☐ The project is not subject to public notice requirements (the source is either more than 1000 ft. from the nearest school, or the source does not emit any toxic compound in Table 2-5-1).
- ☐ For replacement of abatement equipment, the new equipment must have an equal or greater overall abatement efficiency for all pollutants than the equipment being replaced.
- ☐ For alterations of existing sources, for all pollutants the alteration does not result in an increase in emissions.
- ☐ Payment of applicable fees (the minimum permit fee to install and operate each source). See Regulation 3 or contact the Engineering Division for help in determining your fees.

**9. CEQA** *Please answer the following questions pertaining to CEQA (California Environmental Quality Act).*

A. Has another public agency prepared, required preparation of, or issued a notice regarding preparation of a California Environmental Quality Act (CEQA) document (initial study, negative declaration, environmental impact report, or other CEQA document) that analyzes impacts of this project or another project of which it is a part or to which it is related? ☑YES ☐NO If no, go to section 9B.

Describe the document or notice, preparer, and date of document or expected date of completion:

CEC will perform CEQA-equivalent documentation for the proposed amendment and is expected to complete the process by May 1, 2008.

B. List and describe any other permits or agency approvals required for this project by city, regional, state or federal agencies:

Amendment to CEC license.

C. List and describe all other prior or current projects for which either of the following statements is true: (1) the project that is the subject of this application could not be undertaken without the project listed below, (2) the project listed below could not be undertaken without the project that is the subject of this application:

n/a

**10. Certification** *I hereby certify that all information contained herein is true and correct. (Please sign and date this form)*

| GREG BOSSCALEN | MANAGER | [signature] | 12/12/07 |
|---|---|---|---|
| Name of person certifying (print) | Title of person certifying | Signature of person certifying | Date |

Send all application materials to the **BAAQMD Engineering Division, 939 Ellis Street, San Francisco, CA 94109.**

**DATA FORM P**
**Emission Point**

## BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station Plant No: 18143

Emission Point No: P- 11

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **S-** | 41 | **S-** | 42 | **S-** | | **S-** | | **S-** | | | |
| **S-** | | **A-** | 11 | **A-** | 12 | **A-** | | **A-** | | **A-** | |

Exit cross-section area: 220.6 sq. ft. Height above grade: 195 ft.

### Effluent Flow from Stack

| | *Typical Operating Condition* | | *Maximum Operating Condition* | |
|---|---|---|---|---|
| *Actual Wet Gas Flowrate* | 936,640 | cfm | 887,192 | cfm |
| *Percent Water Vapor* | 9.38 | Vol % | 13.37 | Vol % |
| *Temperature* | 180 | °F | 180 | °F |

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☑ yes ☐ no

What pollutants are monitored? NOx, CO, O2/CO2

Person completing this form Nancy Matthews Date 11/27/07

**DATA FORM P**
**Emission Point**

## BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station Plant No: 18143

Emission Point No: P- 12

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **S-** | 43 | **S-** | 44 | **S-** | | **S-** | | **S-** | | | |
| **S-** | | **A-** | 13 | **A-** | 14 | **A-** | | **A-** | | **A-** | |

Exit cross-section area: 220.6 sq. ft. Height above grade: 195 ft.

### Effluent Flow from Stack

| | *Typical Operating Condition* | | *Maximum Operating Condition* | |
|---|---|---|---|---|
| *Actual Wet Gas Flowrate* | 936,640 | cfm | 887,192 | cfm |
| *Percent Water Vapor* | 9.38 | Vol % | 13.37 | Vol % |
| *Temperature* | 180 | °F | 180 | °F |

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☑ yes ☐ no

What pollutants are monitored? NOx, CO, O2/CO2

Person completing this form Nancy Matthews Date 11/27/07

**DATA FORM P**
**Emission Point**

## BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station Plant No: 18143

Emission Point No: P- 13

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **S-** | 45 | **S-** | | **S-** | | **S-** | | **S-** | | | |
| **S-** | | **A-** | | **A-** | | **A-** | | **A-** | | **A-** | |

Exit cross-section area: 0.35 sq. ft. Height above grade: 15 ft.

### Effluent Flow from Stack

| | *Typical Operating Condition* | *Maximum Operating Condition* |
|---|---|---|
| *Actual Wet Gas Flowrate* | 1964 cfm | cfm |
| *Percent Water Vapor* | unk Vol % | Vol % |
| *Temperature* | 300 °F | °F |

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☑ no

What pollutants are monitored? _____

Person completing this form Nancy Matthews Date 11/27/07

DATA FORM P
Emission Point

## BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station Plant No: 18143

Emission Point No: P- 18

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 48 S- S- S- S-
S- A- A- A- A- A-

Exit cross-section area: 0.20 sq. ft. Height above grade: 10.67 ft.

**Effluent Flow from Stack**

| | *Typical Operating Condition* | *Maximum Operating Condition* |
|---|---|---|
| *Actual Wet Gas Flowrate* | 1740 cfm | cfm |
| *Percent Water Vapor* | unk Vol % | Vol % |
| *Temperature* | 770 °F | °F |

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☑ no

What pollutants are monitored?

Person completing this form Nancy Matthews Date 11/27/07

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
*Website: www.baaqmd.gov*

**Data Form C**
**FUEL COMBUSTION SOURCE**

*(for District use only)*

| | | |
|---|---|---|
| | | |

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Gateway Generating Station — Plant No: 18143 — Source No. S-41
2. Equipment Name & Number, or Description: natural gas-fired combustion turbine
3. Make, Model : GE 7FA — Maximum firing rate: 1872 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☑ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated _____
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

**Internal combustion** — Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☑ gas turbine
☐ other _____ _____hp

**Incinerator** ☐ salvage operation ☐ pathological waste Temperature _____°F
☐ liquid waste ☐ other _____ Residence time _____Sec

**Others** ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: _____
☐ open burning ☐ kiln
☐ other _____

8. Overfire air? ☐ yes ☑ no If yes, what percent _____%
9. Flue gas recirculation? ☐ yes ☑ no If yes, what percent _____%
10. Air preheat? ☐ yes ☑ no Temperature _____°F
11. Low $NO_X$ burners? ☑ yes ☐ no Make, Model integral
12. Maximum flame temperature _____°F
13. Combustion products: Wet gas flowrate 936,640 acfm at 180 °F
Typical Oxygen Content 13.0 dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S _____ S _____ S _____ S _____ S _____ S _____ A _____ A _____ A _____
With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S 42 S _____ A 11 A 12 P 11 P _____

Person completing this form: Nancy Matthews — Date: 11/27/07

*(revised 4/05)*

# FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

**SECTION A**: FUEL DATA

| | *Fuel Name* | *Fuel Code*** | *Total Annual Usage**** | *Maximum Possible Fuel Use Rate* | *Typical Heat Content* | *Sulfur Content* | *Nitrogen Content (optional)* | *Ash Content (optional)* |
|---|---|---|---|---|---|---|---|---|
| 1. | natural gas | 189 | 161.9E6 | 1872E6 | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |
| 5. | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| *Use the appropriate units for each fuel* | Natural Gas | therm* | Btu/hr | N/A | N/A | N/A | N/A |
| | Other Gas | MSCF* | MSCF/hr | Btu/MSCF | ppm | N/A | N/A |
| | Liquid | m gal* | m gal/hr | Btu/m gal | wt% | wt% | wt% |
| | Solid | ton | ton/hr | Btu/ton | wt% | wt% | wt% |

**SECTION B**: EMISSION FACTORS (optional)

| | **Fuel Name** | *Fuel Code*** | **Particulates** | | **NOx** | | **CO** | |
|---|---|---|---|---|---|---|---|---|
| | | | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* |
| 1. | | | | | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |

*Use the appropriate units for each fuel:* *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
*Solid = lb/ton*

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***Note:*** * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

| ****Fuel Codes** | | | | ****Basis Codes** | |
|---|---|---|---|---|---|
| ***Code*** | ***Fuel*** | ***Code*** | ***Fuel*** | ***Code*** | ***Method*** |
| 25 | Anthracite coal | 189 | Natural Gas | 0 | Not applicable for this pollutant |
| 33 | Bagasse | 234 | Process gas - blast furnace | 1 | Source testing or other measurement by plant (attach copy) |
| 35 | Bark | 235 | Process gas - CO | 2 | Source testing or other measurement by BAAQMD (give date) |
| 43 | Bituminous coal | 236 | Process gas - coke oven gas | 3 | Specifications from vendor (attach copy) |
| 47 | Brown coal | 238 | Process gas - RMG | 4 | Material balance by plant using engineering expertise and knowledge of process |
| 242 | Bunker C fuel oil | 237 | Process gas - other | 5 | Material balance by BAAQMD |
| 80 | Coke | 242 | Residual oil | 6 | Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA) |
| 89 | Crude oil | 495 | Refuse derived fuel | 7 | Taken from literature, other than AP-42 (attach copy) |
| 98 | Diesel oil | 511 | Landfill gas | 8 | Guess |
| 493 | Digester gas | 256 | Solid propellant | | |
| 315 | Distillate oil | 466 | Solid waste | | |
| 392 | Fuel oil #2 | 304 | Wood - hogged | | |
| 551 | Gasoline | 305 | Wood - other | | |
| 158 | Jet fuel | 198 | Other - gaseous fuels | | |
| 160 | LPG | 200 | Other - liquid fuels | | |
| 165 | Lignite | 203 | Other - solid fuels | | |
| 167 | Liquid waste | | | | |
| 494 | Municipal solid waste | | | | |

*(revised: 6/01)*

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*Website: www.baaqmd.gov*

**Data Form C**
**FUEL COMBUSTION SOURCE**

*(for District use only)*

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Gateway Generating Station — Plant No: 18143 — Source No. S-42
2. Equipment Name & Number, or Description: natural gas fired HRSG
3. Make, Model : tbd — Maximum firing rate: 395 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☑ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated _____
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

**Internal combustion** — Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☐ gas turbine
☐ other _____ _____hp

**Incinerator** ☐ salvage operation ☐ pathological waste Temperature _____°F
☐ liquid waste ☐ other _____ Residence time _____Sec

**Others** ☑ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: _____
☐ open burning ☐ kiln
☐ other _____

8. Overfire air? ☐ yes ☐ no If yes, what percent _____%
9. Flue gas recirculation? ☐ yes ☐ no If yes, what percent _____%
10. Air preheat? ☐ yes ☐ no Temperature _____°F
11. Low $NO_x$ burners? ☐ yes ☐ no Make, Model _____
12. Maximum flame temperature _____°F
13. Combustion products: Wet gas flowrate 887,192 acfm at 180 °F (combined with CTG exhaust)
Typical Oxygen Content 11.0 dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 22.5 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 0 % Mar-May 17 % Jun-Aug 50 % Sep-Nov 33 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S 41 S _____ S _____ S _____ S _____ S _____ A _____ A _____ A _____
With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S _____ S _____ A 11 A 12 P 11 P _____

Person completing this form: Nancy Matthews — Date: 11/27/07

*(revised 4/05)*

# FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

**SECTION A**: FUEL DATA

| | *Fuel Name* | *Fuel Code*** | *Total Annual Usage**** | *Maximum Possible Fuel Use Rate* | *Typical Heat Content* | *Sulfur Content* | *Nitrogen Content (optional)* | *Ash Content (optional)* |
|---|---|---|---|---|---|---|---|---|
| 1. | natural gas | 189 | 174.5 E6 | 395 E6 | | | | |
| 2. | | | (total, including CTG) | (HRSG only) | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |
| 5. | | | | | | | | |

| *Use the appropriate units for each fuel* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Natural Gas | therm* | Btu/hr | N/A | N/A | N/A | N/A |
| | Other Gas | MSCF* | MSCF/hr | Btu/MSCF | ppm | N/A | N/A |
| | Liquid | m gal* | m gal/hr | Btu/m gal | wt% | wt% | wt% |
| | Solid | ton | ton/hr | Btu/ton | wt% | wt% | wt% |

**SECTION B**: EMISSION FACTORS (optional)

| | **Fuel Name** | ***Fuel Code**** | **Particulates** | | **NOx** | | **CO** | |
|---|---|---|---|---|---|---|---|---|
| | | | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* |
| 1. | | | | | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |

*Use the appropriate units for each fuel:* *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
*Solid = lb/ton*

---

***Note:*** * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

| **Fuel Codes** | | | | **Basis Codes** | |
|---|---|---|---|---|---|
| ***Code*** | ***Fuel*** | ***Code*** | ***Fuel*** | ***Code*** | ***Method*** |
| 25 | Anthracite coal | 189 | Natural Gas | 0 | Not applicable for this pollutant |
| 33 | Bagasse | 234 | Process gas - blast furnace | 1 | Source testing or other measurement by plant (attach copy) |
| 35 | Bark | 235 | Process gas - CO | 2 | Source testing or other measurement by BAAQMD (give date) |
| 43 | Bituminous coal | 236 | Process gas - coke oven gas | 3 | Specifications from vendor (attach copy) |
| 47 | Brown coal | 238 | Process gas - RMG | 4 | Material balance by plant using engineering expertise and knowledge of process |
| 242 | Bunker C fuel oil | 237 | Process gas - other | 5 | Material balance by BAAQMD |
| 80 | Coke | 242 | Residual oil | 6 | Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA) |
| 89 | Crude oil | 495 | Refuse derived fuel | 7 | Taken from literature, other than AP-42 (attach copy) |
| 98 | Diesel oil | 511 | Landfill gas | 8 | Guess |
| 493 | Digester gas | 256 | Solid propellant | | |
| 315 | Distillate oil | 466 | Solid waste | | |
| 392 | Fuel oil #2 | 304 | Wood - hogged | | |
| 551 | Gasoline | 305 | Wood - other | | |
| 158 | Jet fuel | 198 | Other - gaseous fuels | | |
| 160 | LPG | 200 | Other - liquid fuels | | |
| 165 | Lignite | 203 | Other - solid fuels | | |
| 167 | Liquid waste | | | | |
| 494 | Municipal solid waste | | | | |

*(revised: 6/01)*

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
*Website: www.baaqmd.gov*

**Data Form C**
**FUEL COMBUSTION SOURCE**

*(for District use only)*

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Gateway Generating Station — Plant No: 18143 — Source No. S-43
2. Equipment Name & Number, or Description: natural gas-fired combustion turbine
3. Make, Model : GE 7FA — Maximum firing rate: 1872 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☑ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated _____
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

**Internal combustion** — Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☑ gas turbine
☐ other _____ _____hp

**Incinerator** ☐ salvage operation ☐ pathological waste Temperature _____°F
☐ liquid waste ☐ other _____ Residence time _____Sec

**Others** ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: _____
☐ open burning ☐ kiln
☐ other _____

8. Overfire air? ☐ yes ☑ no If yes, what percent _____%
9. Flue gas recirculation? ☐ yes ☑ no If yes, what percent _____%
10. Air preheat? ☐ yes ☑ no Temperature _____°F
11. Low $NO_x$ burners? ☑ yes ☐ no Make, Model integral
12. Maximum flame temperature _____°F
13. Combustion products: Wet gas flowrate 936,640 acfm at 180 °F
Typical Oxygen Content 13.0 dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S _____ S _____ S _____ S _____ S _____ S _____ A _____ A _____ A _____
With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S 44 S _____ A 13 A 14 P 12 P _____

Person completing this form: Nancy Matthews — Date: 11/27/07

*(revised 4/05)*

# FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

**SECTION A**: FUEL DATA

| | *Fuel Name* | *Fuel Code*** | *Total Annual Usage**** | *Maximum Possible Fuel Use Rate* | *Typical Heat Content* | *Sulfur Content* | *Nitrogen Content (optional)* | *Ash Content (optional)* |
|---|---|---|---|---|---|---|---|---|
| 1. | natural gas | 189 | 161.9E6 | 1872E6 | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |
| 5. | | | | | | | | |

| *Use the appropriate units for each fuel* | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Natural Gas | therm* | Btu/hr | N/A | N/A | N/A | N/A |
| | Other Gas | MSCF* | MSCF/hr | Btu/MSCF | ppm | N/A | N/A |
| | Liquid | m gal* | m gal/hr | Btu/m gal | wt% | wt% | wt% |
| | Solid | ton | ton/hr | Btu/ton | wt% | wt% | wt% |

**SECTION B**: EMISSION FACTORS (optional)

| | **Fuel Name** | ***Fuel Code**** | **Particulates** | | **NOx** | | **CO** | |
|---|---|---|---|---|---|---|---|---|
| | | | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* | *Emission Factor* | ***Basis Code* |
| 1. | | | | | | | | |
| 2. | | | | | | | | |
| 3. | | | | | | | | |
| 4. | | | | | | | | |

*Use the appropriate units for each fuel:* *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
*Solid = lb/ton*

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***Note:*** * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

****Fuel Codes**

| *Code* | *Fuel* | *Code* | *Fuel* |
|---|---|---|---|
| 25 | Anthracite coal | 189 | Natural Gas |
| 33 | Bagasse | 234 | Process gas - blast furnace |
| 35 | Bark | 235 | Process gas - CO |
| 43 | Bituminous coal | 236 | Process gas - coke oven gas |
| 47 | Brown coal | 238 | Process gas - RMG |
| 242 | Bunker C fuel oil | 237 | Process gas - other |
| 80 | Coke | 242 | Residual oil |
| 89 | Crude oil | 495 | Refuse derived fuel |
| 98 | Diesel oil | 511 | Landfill gas |
| 493 | Digester gas | 256 | Solid propellant |
| 315 | Distillate oil | 466 | Solid waste |
| 392 | Fuel oil #2 | 304 | Wood - hogged |
| 551 | Gasoline | 305 | Wood - other |
| 158 | Jet fuel | 198 | Other - gaseous fuels |
| 160 | LPG | 200 | Other - liquid fuels |
| 165 | Lignite | 203 | Other - solid fuels |
| 167 | Liquid waste | | |
| 494 | Municipal solid waste | | |

****Basis Codes**

| *Code* | *Method* |
|---|---|
| 0 | Not applicable for this pollutant |
| 1 | Source testing or other measurement by plant (attach copy) |
| 2 | Source testing or other measurement by BAAQMD (give date) |
| 3 | Specifications from vendor (attach copy) |
| 4 | Material balance by plant using engineering expertise and knowledge of process |
| 5 | Material balance by BAAQMD |
| 6 | Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA) |
| 7 | Taken from literature, other than AP-42 (attach copy) |
| 8 | Guess |

*(revised: 6/01)*

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*Website: www.baaqmd.gov*

**Data Form C**
**FUEL COMBUSTION SOURCE**

*(for District use only)*

| | | |
|---|---|---|
| | | |

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

(If unknown, leave blank)

1. Company Name: Gateway Generating Station — Plant No: 18143 — Source No. S-44
2. Equipment Name & Number, or Description: natural gas fired HRSG
3. Make, Model : tbd — Maximum firing rate: 395 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☑ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated _____
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

**Internal combustion** Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☐ gas turbine
☐ other _____ _____hp

**Incinerator** ☐ salvage operation ☐ pathological waste Temperature _____°F
☐ liquid waste ☐ other _____ Residence time _____Sec

**Others** ☑ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: _____
☐ open burning ☐ kiln
☐ other _____

8. Overfire air? ☐ yes ☐ no If yes, what percent _____%
9. Flue gas recirculation? ☐ yes ☐ no If yes, what percent _____%
10. Air preheat? ☐ yes ☐ no Temperature _____°F
11. Low $NO_x$ burners? ☐ yes ☐ no Make, Model _____
12. Maximum flame temperature _____°F
13. Combustion products: Wet gas flowrate 887,192 acfm at 180 °F (combined with CTG exhaust)
Typical Oxygen Content 11.0 dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 22.5 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 0 % Mar-May 17 % Jun-Aug 50 % Sep-Nov 33 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S 43 S _____ S _____ S _____ S _____ S _____ A _____ A _____ A _____
With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S _____ S _____ A 13 A 14 P 12 P _____

Person completing this form: Nancy Matthews — Date: 11/27/07

*(revised 4/05)*

# Exhibit No. 325

EPA Finding and Notice of Violation dated August 13, 2009

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**REGION IX**
**75 Hawthorne Street**
**San Francisco, CA 94105-3901**

AUG 13 2009

CERTIFIED MAIL # 7006 2150 00001 4941 2215
RETURN RECEIPT REQUESTED

IN REPLY: AIR-5
REFER TO: Docket No. R9-09-011

Mr. Randy S. Livingston
Vice President – Power Generation
Pacific Gas and Electric Company
P.O. Box 770000, Mail Code N11E
San Francisco, CA 94177

Re: PG & E Gateway Generating Station. Finding and Notice of Violation

Dear Mr. Livingston:

Enclosed is a copy of a Finding and Notice of Violation ("NOV") issued pursuant to section 113(a)(1) of the Clean Air Act, 42 U.S.C. §§ 7401-7671q (the "Act"), notifying you that the United States Environmental Protection Agency ("EPA"), Region IX, finds that Pacific Gas and Electric Company's (PG&E) Gateway Combined Cycle Generating Station located in Contra Costa County, California (the "Facility") is in violation of the Clean Air Act ("Act").

You should be aware that section 113(a)(1) of the Act authorizes EPA to issue an order requiring compliance with the requirements of the Act, issue an administrative penalty order, or commence a civil action seeking an injunction and/or a civil penalty. Furthermore, section 113(c) of the Act provides for criminal penalties in certain cases.

In addition, section 306 of the Act, 42 U.S.C. § 7606, the regulations promulgated thereunder (2 C.F.R. Part 180), and Executive Order 11738 provide that facilities to be utilized in federal contracts, grants, and loans must be in full compliance with the Act and all regulations promulgated pursuant to it. A violation of the Act may result in the PG&E Facility being declared ineligible for participation in any federal contract, grant, or loan.

If you wish to discuss the enclosed NOV, you may request a conference with EPA within ten (10) working days of receipt of this NOV. The conference will afford PG&E an opportunity to present information bearing on the finding of violation, the nature of the violations, and any efforts it may have taken or proposes to take to achieve compliance.

*Printed on Recycled Paper*

If you have any questions pertaining to this NOV, please contact Steve Frey of the Air Enforcement Office at (415) 972-3796, or have your attorney contact Allan Zabel, Office of Regional Counsel, at (415) 972-3902.

Thank you for your cooperation in this matter.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosure

cc: Mr. Jack Broadbent (BAAQMD)
Mr. Jim Ryden (CARB)
Mr. Dave Farabee (e-mail)

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**REGION IX**
**75 Hawthorne Street**
**San Francisco, CA 94105-3901**

**AUG 13 2009**

IN REPLY: AIR-5
REFER TO: Docket No. R9-09-11

Mr. Jack Broadbent
Executive Officer/Air Pollution Control Officer
Bay Area Air Quality Management District District
939 Ellis Street
San Francisco, CA 94109

Dear Mr. Broadbent:

Enclosed for your information is a copy of a Finding and Notice of Violation ("NOV") that the United States Environmental Protection Agency ("EPA"), Region IX, issued to Pacific Gas and Electric (PG&E) for violations of the Clean Air Act ("Act") at its Gateway Combined Cycle Generating Station located in Contra Costa County, California.

The purpose of the NOV is to notify PG&E that EPA finds that it has violated certain provisions of the California State Implementation Plan. The violations are set forth more specifically in the enclosed NOV. The NOV has been issued pursuant to section 113(a)(1) of the Act, 42 U.S.C. §§ 7401-7671q.

The Act also provides that after 30 days from the issuance of an NOV, EPA may determine if any further action will be taken pursuant to section 113 of the Act.

If you have any questions concerning this NOV, please contact Steve Frey, Air Enforcement Office, at (415) 972-3796, or frey.steve@epa.gov.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosure

*Printed on Recycled Paper*

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**REGION IX**
**75 Hawthorne Street**
**San Francisco, CA 94105-3901**

**AUG 13 2009**

IN REPLY: AIR-5
REFER TO: Docket No. R9-09-11

Mr. Jim Ryden
Chief, Enforcement Division
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Dear Mr. Ryden:

Enclosed for your information is a copy of a Finding and Notice of Violation ("NOV") that the United States Environmental Protection Agency ("EPA"), Region IX, issued to Pacific Gas and Electric (PG&E) for violations of the Clean Air Act ("Act") at its Gateway Combined Cycle Generating Station located in Contra Costa County, California.

The purpose of the NOV is to notify PG&E that EPA finds that it has violated certain provisions of the California State Implementation Plan. The violations are set forth more specifically in the enclosed NOV. The NOV has been issued pursuant to section 113(a)(1) of the Act, 42 U.S.C. §§ 7401-7671q.

The Act also provides that after 30 days from the issuance of an NOV, EPA may determine if any further action will be taken pursuant to section 113 of the Act.

If you have any questions concerning this NOV, please contact Steve Frey, Air Enforcement Office, at (415) 972-3796, or frey.steve@epa.gov.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosure

*Printed on Recycled Paper*

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION IX

| | | |
|---|---|---|
| In the Matter of: | ) | |
| PACIFIC GAS AND ELECTRIC COMPANY | ) | Docket No. R9-09-11 |
| | ) | FINDING AND |
| Proceeding under Section 113(a) of the Clean Air Act, 42 U.S.C. § 9613(a) | ) | NOTICE OF VIOLATION |

STATUTORY AND REGULATORY AUTHORITY

1. This Finding and Notice of Violation ("FNOV") is issued to the Pacific Gas and Electric Company ("PG&E") for violations of the Clean Air Act at PG&E's Gateway Generating Station ("GGS") located in Contra Costa County near Antioch, California. This FNOV is issued pursuant to Section 113(a)(1) of the Act, 42 U.S.C. § 7413(a)(1). Section 113(a)(1) of the Act requires the Administrator of the United States Environmental Protection Agency ("EPA") to notify any person in violation of an applicable state implementation plan ("SIP") or a permit when the Administrator finds that person to be in such violation. The authority to issue this FNOV has been delegated to the Regional Administrator of EPA, Region IX, and re-delegated to the Director of the Air Division of EPA, Region IX.

2. The Administrator of the Environmental Protection Agency ("EPA"), pursuant to authority under Section 109 of the Clean Air Act (the "Act"), 42 U.S.C. § 7409, promulgated National Ambient Air Quality Standards ("NAAQS") for certain criteria pollutants, including $PM_{10}$, carbon monoxide, and nitrogen dioxide. 40 C.F.R. §§ 50.6, 50.8, and 50.11.

3. Pursuant to Section 107(d) of the Act, 42 U.S.C.

§ 7407(d), the Administrator promulgated lists of attainment status designations for each air quality control region ("AQCR") in every State. These lists identify the attainment status of each AQCR for each of the criteria pollutants. The carbon dioxide, $PM_{10}$, and nitrogen dioxide attainment status designations for the California AQCRs are listed at 40 C.F.R. § 81.305.

4. The Bay Area Air Quality Management District ("BAAQMD") has primary jurisdiction over major stationary sources of air pollution sources in the San Francisco Bay Area Intrastate AQCR. 40 C.F.R. 81.21. This jurisdiction includes GGS.

5. Section 161 of the Act, 42 U.S.C. § 7471, requires that each state implementation plan ("SIP") contain provisions to implement the Act's Prevention of Significant Deterioration ("PSD") program for areas of that state which are designated as being in attainment with any NAAQS for a criteria pollutant. The PSD program applies to major new sources of air pollution.

6. The PSD permitting program for the San Francisco Bay Area Intrastate AQCR is the federal PSD program, which is set forth at 40 C.F.R. § 52.21 ("PSD Program").

7. The PSD Program requires, among other things, that the owner or operator of a new major stationary source of air pollution obtain a PSD permit, which complies with the requirements of 40 C.F.R. § 52.21, prior to constructing a new major source of air pollution. The PSD permit must require, among other things, that the best available control technology ("BACT") be installed at the source being constructed or modified. The definition of a major modification is set forth in

40 C.F.R. § 52.21.

FINDINGS OF FACT AND LAW

8. PG&E generates electricity at GGS, which is a nominal 530 megawatt, natural gas-fired, combined cycle, combustion turbine power plant. At all times relevant to this FNOV, GGS has been and continues to be a major source of air pollution. GGS is located in Contra Costa County near Antioch, California, which is under the jurisdiction of BAAQMD and EPA.

9. On July 24, 2001, PG&E's predecessor in interest, Delta, LLC ("Mirant"), obtained a PSD permit from the BAAQMD as part of a single, comprehensive Authority to Construct. BAAQMD issued that PSD permit pursuant to the authority set forth in 40 C.F.R. 52.21 and a delegation of authority from EPA dated April 26, 1986. Such delegation of authority to issue PSD permits and implement the PSD Program is allowed under 40 C.F.R. 52.21(u).

10. The delegation of authority to BAAQMD to implement the PSD Program was revoked on March 3, 2003. A partial re-delegation of authority to BAAQMD to implement the PSD Program was issued on June 21, 2004.

11. At some point during the time period between February 2002 and September 2002, Mirant ceased construction of GGS. This cessation of construction lasted more than 18 months.

12. Pursuant to the PSD Program, 40 C.F.R. 52.21(r), where construction of a major new source pursuant to a PSD permit is discontinued for 18 months or more, the PSD permit automatically expires unless an extension is granted by the Administrator of EPA or someone who currently possesses a valid delegation of authority from the Administrator to grant such an extension.

13. Between the time the PSD permit for GGS was issued to Mirant and the latest time that PSD permit would have automatically expired due to discontinued construction of GGS, no valid extension of the PSD permit was requested from or issued by the Administrator of EPA or someone who currently possessed a valid delegation of authority from the Administrator to grant such an extension. Therefore, the PSD permit automatically expired when construction of GGS had ceased for 18 months.

14. PG&E took over ownership of GGS from Mirant on November 30, 2006, and restarted construction of GGS in January 2007. At the time PG&E took over ownership of GGS and restarted construction of GGS, the PSD permit for the construction and operation of GGS had expired. PG&E has not applied for a new PSD permit.

15. PG&E failed to obtain a valid PSD permit prior to restarting construction of and operating GGS. PG&E's failure to have a valid PSD permit continues to this time.

FINDING OF VIOLATIONS

16. PG&E violated the SIP and the Act by restarting construction of and operating GGS, a major new source of air pollution, without obtaining a valid PSD permit.

ENFORCEMENT

17. Section 113(a)(1) of the Act provides that at any time after the expiration of 30 days following the date of the issuance of this FNOV, EPA may, without regard to the period of violation:

- issue an order requiring compliance with the requirements of the SIP or permit, or

- issue an administrative penalty order pursuant to Section 113(d) of the Act for civil administrative penalties of up to $32,500 per day of violation, or
- bring a civil action pursuant to Section 113(b) for injunctive relief and/or civil penalties of not more than $32,500 per day for each violation.

42 U.S.C. § 7413(a)(1), as amended by the Federal Civil Penalties Inflation Adjustment Act of 1990, Pub. L. 101-410, as amended, & 40 C.F.R. § 19. Furthermore, for any person who knowingly violates any SIP or permit requirement more than 30 days after the date of the issuance of a FNOV, Section 113(c) of the Act provides for criminal penalties, imprisonment, or both. 42 U.S.C. § 7413(c)(3).

In addition, under Section 306(a) of the Act, the regulations promulgated thereunder (40 C.F.R. Part 32), and Executive Order 11738, facilities to be used in federal contracts, grants, and loans must be in full compliance with the Act and all regulations promulgated pursuant to it. Violation of the Act may result in the GGS being declared ineligible for participation in any federal contract, grant, or loan.

PENALTY ASSESSMENT CRITERIA

18. Section 113(e)(1) of the Act states that the Administrator or a court, as appropriate, shall, in determining the amount of any penalty to be assessed, take into consideration (in addition to such other factors as justice may require) the size of the business, the economic impact of the penalty of the business, the violator's full compliance history and good faith efforts to comply, the duration of the violation as established

by any credible evidence (including evidence other than the applicable test method), payment by the violator of penalties previously assessed for the same violation, the economic benefit of noncompliance, and the seriousness of the violation. 42 U.S.C. § 7413(e)(1).

Section 113(e)(2) of the Act allows the Administrator or a court to assess a penalty for each day of violation. 42 U.S.C. § 7413(e)(2). For the purpose of determining the number of days of violation, where EPA makes a prima facie showing that the conduct or events giving rise to a violation are likely to have continued or recurred past the date of the issuance of a FNOV, EPA shall presume the days of violation to include the date of issuance of the FNOV and each and every day thereafter until the violator establishes that continuous compliance has been achieved, except to the extent that the violator can prove by a preponderance of the evidence that there were intervening days during which no violation occurred or that the violation was not continuing in nature.

OPPORTUNITY FOR CONFERENCE

19. PG&E may, upon request, arrange to have a conference with EPA to discuss this matter. A conference would enable PG&E to present evidence bearing on the finding of violation, the nature of the violation, and any efforts that it may have taken or proposes to take to achieve compliance. If PG&E wishes to take advantage of this opportunity, it must make a request for a conference within ten (10) days of receipt of this FNOV. PG&E, if it chooses to request a conference, may choose to be represented by counsel at the conference. Any request for a

conference or other inquiries concerning this FNOV should be made in writing to:

Allan Zabel
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street (ORC-2)
San Francisco, CA 94105
(415) 972-3902

8-12-09
Date

Deborah Jordan
Director, Air Division
EPA Region IX

**BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA**
**1516 NINTH STREET, SACRAMENTO, CA 95814**
**1-800-822-6228 – WWW.ENERGY.CA.GOV**

**IN THE MATTER OF THE COMPLAINT AGAINST**

***GATEWAY GENERATING STATION***

**Docket No. 00-AFC-1C**
**PROOF OF SERVICE**
***(Revised 7/28/09)***

**PROJECT OWNER**

Steve Royal
Pacific Gas & Electric Company
Gateway Generating Station
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**PROJECT OWNER'S COUNSEL**

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sgalati@gb-llp.com

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## DECLARATION OF SERVICE

I, Ashley Y. Garner, declare that on September 9, 2009, I served and filed copies of the attached **REBUTTAL EXHIBITS PROPOSED BY PG&E.** The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

**(*Check all that Apply*)**

**For service to all other parties:**

_X_ sent electronically to all email addresses on the Proof of Service list;

___by personal delivery or by depositing in the United States mail at Sacramento, California with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses **NOT** marked "email preferred."

***AND***

**For filing with the Energy Commission:**

_X_ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below **(preferred method);**

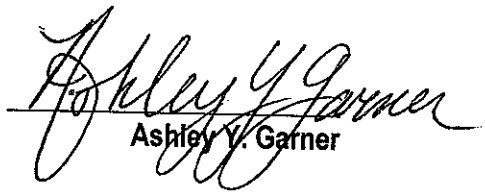
***OR***

___depositing in the mail an original and 12 paper copies, as follows:

**CALIFORNIA ENERGY COMMISSION**
Attn: Docket No. 00-AFC-1C
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.



**Ashley Y. Garner**