# APPENDIX D

# BACT INFORMATION

# Appendix D

## List of Contents

# BOWIE POWER STATION
# TURBINES AND DUCT BURNERS
# $NO_x$ REDUCTION AND
# COST EFFECTIVENESS

| | |
|---|---|
| Interest Rate | 7% |
| Equipment Life (years) | 15 |
| Capital Recovery Factor | 0.11 |

| | Uncontrolled Emissions (tons/year)[a] | Controlled Emissions (tons/year)[a] | Emission Reduction (tons/year) | Capital Investment[b] | Capital Recovery (per year) | Operating Costs[b] (per year) | Total Annual Cost (per year) | Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|
| **$EM_x$™** | 295.8 | 69.5 | 226.3 | $15,651,488 | $1,718,449 | $5,260,678 | $6,979,127 | $30,840 |
| **SCR** | 295.8 | 69.5 | 226.3 | $12,687,346 | $1,393,002 | $4,961,113 | $6,354,115 | $28,078 |
| **Difference** | | | | $2,964,142 | | $299,565 | $625,012 | $2,762 |

[a]From spreadsheet "Bowie Power Station, Combined Turbine and Duct Burner Annual Emissions" (see Appendix B)

[b]From presentation "EMx™ Multi-Pollutant Control Technology", Presented at GreenTech Connect Forum, by Jeff Valmus EmeraChem Power™, Pasadena, CA August 3, 2009.

Capital Recover Factor calculated in accordance with "EPA Air Pollution Control Cost Manual", equation 2.8a (page 2-21):

$$\text{Capital Recover Factor} = \frac{(\text{interest rate} \times (1 + \text{interest rate})^{\text{equipment life}})}{((1 + \text{interest rate})^{\text{equipment life}} - 1)}$$

$$\text{Emission Reduction } \frac{\text{tons}}{\text{year}} = \text{Uncontrolled Emissions } \frac{\text{tons}}{\text{year}} - \text{Controlled Emissions } \frac{\text{tons}}{\text{year}}$$

$$\text{Capital Recovery } \frac{\$}{\text{year}} = \text{Capital Investment } \$ \times \text{Capital Recovery Factor}$$

$$\text{Total Annual Cost } \frac{\$}{\text{year}} = \text{Capital Recovery } \frac{\$}{\text{year}} + \text{Operating Costs } \frac{\$}{\text{year}}$$

$$\text{Cost Effectiveness } \frac{\$}{\text{year}} = \frac{\text{Total Annual Cost (\$/year)}}{\text{Emission Reduction (tons/year)}}$$

EPA/452/B-02-001

# EPA AIR POLLUTION CONTROL COST MANUAL

Sixth Edition

EPA/452/B-02-001

January 2002

United States Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Annualization is a process similar to EUAC but is not limited to constant cash flows. It involves determining the net present value of each alternative equipment investment and then determining the equal (in nominal terms) payment that would have to be made at the end of each year to attain the same level of expenditure. In essence, annualization involves establishing an annual "payment" sufficient to finance the investment for its entire life, using the formula:

$$PMT = NPV\left(\frac{i}{1-(1+i)^{-n}}\right) \qquad (2.7)$$

where *PMT* is the equivalent uniform payment amount over the life of the control, *n*, at an interest rate, *i*. *NPV* indicates the present value of the investment as defined above in equation 2.6.

Engineering texts call this payment the capital recovery cost (*CRC*), which they calculate by multiplying the *NPV* of the investment by the capital recovery factor (*CRF*):

$$CRC = NPV \times CRF \qquad (2.8)$$

where *CRF* is defined according to the formula:

$$\mathrm{CRF} = \left(\frac{\mathrm{i}\,(1+\mathrm{i})^{\mathrm{n}}}{(1+\mathrm{i})^{\mathrm{n}}-1}\right) \qquad (2.8a)$$

The *CRF* equation is a transformation of the *PMT* form in equation 2.7 and returns the same information. Table A.2 in Appendix A lists the *CRF* for discount rates between 5.5 percent and 15 percent for annualization periods from one to 25 years.

2.4.4.5 Other Financial Analysis Tools

Many firms make investment decisions based upon the return on investment (*ROI*) of the proposed capital purchase, rather than the magnitude of its net present value. In and of itself, the ROI of an investment opportunity is of little use. For most pollution control investments, *ROI* analysis does not provide much in the way of useful information because, like a payback analysis, it must have positive cash flows to work properly. Calculated by dividing annual net income by the investment's capital cost, results in a percentage of the investment that is returned each year. The decision rule one should apply for *ROI* analysis is if the resulting percentage is at least as large as some established minimum rate of return, then the investment would be worth while. However, different industries require different rates of return on investments, and even within an industry, many different rates can be found. Analysts should consult with their firm's financial officers or an industrial association to determine what percentage would apply.

# EMx™ Multi-Pollutant Control Technology

## EmeraChem Power™

Jeff Valmus
Vice President and General Manager

August 3, 2009
Pasadena Convention Center

# Cost Effectiveness

- Capital Recovery Analysis
  - 10 % interest rate
  - 15 year annuity
  - Fixed current dollars

| | Cost Effectiveness | | | |
|---|---|---|---|---|
| | LM6000 | | GE 7FA | |
| | SCR | EMx | SCR | EMx |
| Total Capital Investment | $ 4,104,730 | $ 7,256,357 | $ 12,687,346 | $ 15,651,488 |
| Annual Operating Cost | $ 1,663,190 | $ 2,094,840 | $ 4,961,113 | $ 5,260,678 |
| Levelized Cost of Control, $/ton-NOx | 20,952 | 22,694 | 27,854 | 27,996 |

*Total Capital Investment costs include the system equipment, catalyst, engineering and installation, commissioning and start-up and shipping charges*

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| CA-1050 | 9/11/00 | IDC Bellingham | SCR | 1.5 | ppm | LAER |
| CA-1192 | 6/21/11 | Avenal Power Center LLC | SCR, Dry Low $NO_x$ Combustors | 1.5 | ppmvd | BACT - no duct firing |
| AZ-0047 | 12/1/2004 | Dome Valley Energy Partners, LLC - Wellton Mohawk Generating Station | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmv | BACT |
| AZ-0039 | 3/7/03 | Salt River Project/Santan Gen. Plant | SCR | 2 | ppm | LAER |
| AZ-0043 | 11/12/03 | Duke Energy Arlington Valley | SCR | 2.0 | ppm | BACT |
| CA-1177 | 7/22/09 | Otay Mesa | SCR | 2 | ppmv | BACT -CA |
| CA | 5/21/01 | Three Mountain Power | SCR | 2.0 | ppm | BACT-CA |
| CA-0997 | 9/1/03 | Sacramento Municipal Utility District | SCR | 2.0 | ppm | LAER |
| CA-1096 | 2/1/2004 | Vernon City Power & Light | SCR/DLN | 2 | ppm | BACT-CA |
| CA-1144 | 4/25/07 | Caithness Blythe II, LLC | SCR | 2.0 | ppm | BACT-CA |
| CA-1191 | 3/11/10 | Victorville 2 Hybrid Power Project | SCR | 2.0 | ppmvd | BACT-CA |
| CA-1192 | 6/21/11 | Avenal Power Center LLC | SCR, Dry Low $NO_x$ Combustors | 2.0 | ppmvd | BACT-CA |
| CA-1211 | 3/11/11 | Colusa Generating Station | Dry Low NOx Combustors, SCR | 2.0 | ppmvd | BACT-CA |
| CA-1212 | 10/18/11 | Palmdale Hybrid Power Project | Dry Low $NO_x$ Combustors, SCR | 2.0 | ppm | BACT-CA |
| CA | 7/1/2008 | Gateway Generating Station | SCR/DLN | 2 | ppm | BACT-CA |
| CA | 3/1/2005 | Los Esteros - Calpine | SCR, water injection | 2 | ppm | BACT-CA |
| CA | 5/27/2003 | Magnolia Power Project | SCR | 2 | ppm | BACT-CA |
| CA | 12/1/2002 | Palomar Escondido - Sempra | SCR/DLN | 2 | ppm | BACT-CA |
| CA | 6/1/2007 | Russell City Energy Center | SCR/DLN | 2 | ppm | BACT-CA |
| CA | 8/1/2006 | San Joaquin Valley Energy Center | SCR/DLN | 2 | ppm | BACT-CA |
| CA | | Sunlaw Cogen Power | SCONox | 2 | ppm | BACT-CA |
| CT-0148 | 6/22/99 | Lake Road Generating Company | SCR, Dry Low $NO_x$ Combustion | 2 | ppmv | LAER |
| CT-0151 | 2/25/08 | Kleen Energy Systems, LLC - with duct burner | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppm | LAER |
| CT | | PDC-El Paso, Meridan | SCR | 2 | ppm | |
| DE-0024 | 1/30/13 | Garrison Energy Center LLC/Calpine Corporation | SCR, Low $NO_x$ Combustors | 2.0 | ppm | LAER |
| FL-0263 | 2/8/05 | Florida Power and Light Turkey Point Power Plant | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | BACT |
| FL-0280 | 5/30/06 | Florida Municipal Power Agency - Treasure Coast Energy Center | SCR | 2.0 | ppmvd | BACT |
| FL-0286 | 1/10/07 | Florida Power and Light West County Energy Center | SCR, Dry Low $NO_x$ Combustion, Water Injection | 2.0 | ppmvd | BACT |
| FL-0303 | 7/30/08 | Florida Power and Light West County Energy Center Unit 3 | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | BACT |

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| FL-0304 | 9/8/08 | Florida Municipal Power Agency - Cane Island Power Park | SCR | 2.0 | ppmvd | BACT |
| GA | 5/30/12 | Effingham County Power Plant | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | BACT |
| GA | | McDonough | SCR/DLN | 2 | ppm | |
| ID-0018 | 6/25/10 | Idaho Power Company - Langley Gulch Power Plant | SCR, DLN, Good Combustion Practices | 2.0 | ppmvd | BACT |
| IN-0158 | 12/3/12 | St. Joseph Energy Center LLC | SCR and DLN | 2.0 | ppmvd | BACT |
| MA-0024 | 4/16/99 | ANP Blackstone | SCR, Dry Low $NO_x$ Combustion | 2 | ppmv | LAER |
| MA-0025 | 8/4/99 | ANP Bellingham | SCR, Dry Low $NO_x$ Combustion | 2 | ppmv | LAER |
| MA-0029 | 1/25/00 | Sithe Mystic Development | SCR, Dry Low $NO_x$ Combustion | 2 | ppmv | LAER |
| MA | 2/22 | Cabot Power Island End Cogeneration Project | SCR | 2 | ppm | |
| MA | 12/14 | Fore River Station, Weymouth | SCR | 2 | ppm | |
| NC | | Southern Power CO - Plant Rowan County | SCR | 2 | ppm | |
| NJ | 9/13/12 | Hess Newark Energy Center | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | BACT |
| NJ | 5/31/12 | Woodbridge Energy Center | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | BACT |
| NV-0035 | 8/16/05 | Sierra Pacific Power Company - Tracy Substation Expansion Project | SCR | 2.0 | ppm | BACT |
| NV-0037 | 5/14/04 | Sempra Energy Resources - Copper Mountain Power | SCR, Dry Low $NO_x$ Combustion, Steam Injection | 2.0 | ppmvd | BACT |
| NV-0038 | 6/28/05 | Ivanpah Energy Center, L.P. | Dry Low NOx Combustors, SCR | 2.0 | ppmvd | BACT |
| NY-0095 | 5/10/06 | Caithness Bellport, LLC | SCR | 2.0 | ppmvd | BACT |
| NY-0098 | 1/19/07 | New Athen Generating CO. LLC - Athens Generating Plant | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | LAER |
| NY-0100 | 6/23/05 | Empire Generating CO. LLC - Empire Power Plant - turbine only | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | LAER |
| NY | 9/27/12 | Cricket Valley Energy Center LLC | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | LAER |
| OH-0352 | 6/18/13 | Oregon Clean Energy Center | SCR, Dry Low NOx Combustors, Lean Fuel Technology | 2.0 | ppmvd | BACT |
| OK-0129 | 1/23/09 | Associated Electric Cooperative Inc - Chouteau Power Plant | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppm | BACT |
| OR-0041 | 8/8/05 | Diamond Wanapa I, L. P. - Wanapa Energy Center | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppm | BACT |
| OR-0048 | 12/29/10 | Portland General Electric Carty Plant | SCR | 2.0 | ppm | BACT |
| OR | 1/6/2005 | Turner Energy Center LLC | SCR | 2 | ppm | |
| OR | 1/18/02 | Umatilla Generating - PG&E | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | |

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| PA-0226 | 4/9/02 | Limerick Partners, LLC | Low NOx Burners | 2.0 | ppm | LAER |
| PA-0286 | 1/13/13 | Moxie Energy LLC/Patriot Energy Plant | SCR | 2.0 | ppmvd | BACT |
| PA-0291 | 4/23/13 | Hickory Run Energy LLC | SCR | 2.0 | ppmvd | Other |
| RI-0019 | 5/3/00 | Reliant Energy Hope Gen. Facility | SCR, Dry Low $NO_x$ Combustion | 2 | ppmv | BACT |
| TX-0546 | 6/7/09 | Pattillo Branch Power Company LLC | SCR | 2.0 | ppmvd | BACT |
| TX-0547 | 6/22/09 | Lamar Power Partners II LLC | SCR | 2.0 | ppmvd | BACT |
| TX-0548 | 8/18/09 | Madison Bell Partners LP | SCR | 2.0 | ppmvd | BACT |
| TX-0590 | 8/5/10 | Pondera Capital Management GP INC - King Power Station | DLN, SCR | 2.0 | ppmvd | LAER |
| TX-0600 | 9/1/11 | Thomas C. Ferguson Power Plant | SCR | 2.0 | ppmvd | BACT |
| TX-0618 | 10/15/12 | Channel Energy Center LLC | SCR | 2.0 | ppmvd | LAER |
| TX-0619 | 9/26/12 | Deer Park Energy Center | SCR | 2.0 | ppmvd | LAER |
| TX-0620 | 9/12/12 | ES Josllin Power Plant | SCR | 2.0 | ppmvd | BACT |
| VA-0315 | 12/17/10 | Virginia Electric and Power Company - Warren County Power Plant - Dominion | SCR, Dry Low NOx Combustion | 2.0 | ppmvd | BACT |
| VA | 4/30/13 | Stonewall, LLC | Dry Low NOx Combustors, SCR | 2.0 | ppmvd | LAER |
| WA | 4/20/03 | Plymouth Generating Facility | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | |
| WA-0299 | 4/17/03 | Sumas Energy 2 - NESCO | SCR, Dry Low $NO_x$ Combustion | 2.0 | ppmvd | BACT - Project Cancelled |
| UT | | Calpine Corp Vineyard Energy Center LLC | SCR/DLN | 2 | ppm | |
| UT | | Summit Vinyard LLC | SCR/DLN | 2 | ppm | |
| UT-0066 | 5/17/04 | Pacificorp - Currant Creek Power Project | SCR, Dry Low $NO_x$ Combustion | 2.25 | ppm | |
| AZ-0038 | 4/30/02 | Gila Bend Power Generation Station | SCR, Dry Low $NO_x$ Combustion | 2.5/2.0 | ppmv | BACT |
| AL-0185 | 7/12/02 | Barton Shoals Energy, LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppm | BACT |
| AZ-0033 | 3/22/01 | Mesquite Generating Station | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| AZ-0034 | 2/15/01 | Harquahala Generating Project | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| CA-1209 | 3/11/10 | High Desert Power Project LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| CA-1213 | 3/1/01 | Mountainview Power Project | SCR | 2.5 | ppm | BACT-CA |
| CA | 5/30/01 | Contra Costa | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT-CA |
| CA | 12/18/01 | Elk Hills Power Project | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT-CA |
| CA | 2/1/02 | Delta Energy Center | SCR | 2.5 | ppm | BACT-CA |
| CA | 12/1/2004 | La Paloma PG&E | SCR | 2.5 | ppm | BACT-CA |
| CA | 11/9/2004 | Los Medanos - Calpine | SCR | 2.5 | ppm | BACT-CA |
| CA | 9/1/01 | Metcalf Energy Center | SCR | 2.5 | ppm | BACT-CA |
| CA | 12/1/2004 | Pastoria Energy LLC | SCR/DLN or XONON | 2.5 | ppm | BACT-CA |

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| CA | 12/1/2000 | Suter Power Project | SCR | 2.5 | ppm | BACT-CA |
| CA | | Texaco Global - Sunrise Cogeneration | SCR | 2.5 | ppm | BACT-CA |
| CA | 3/1/01 | Western Midway Sunset Power Project | SCR | 2.5 | ppm | BACT-CA |
| CA-1142 | 12/23/04 | Calpine Western Regional Office - Pastoria Energy Facility | XONON or SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT-CA |
| CA-1143 | 8/16/04 | Calpine Corporation - Sutter Power Plant | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT-CA |
| FL-0225 | 8/17/01 | El Paso Broward Energy Center | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| FL-0226 | 9/11/01 | El Paso Manatee Energy Center | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| FL-0227 | 9/7/01 | El Paso Belle Glade Energy Center | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| FL-0241 | 1/17/02 | CPV Cana Power Generation Facility | SCR, Dry Low $NO_x$ Combustion, Wet Injection | 2.5 | ppmvd | BACT |
| FL-0244 | 4/16/03 | FPL Martin | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| FL-0245 | 4/15/03 | FPL Manatee - Unit 3 | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| FL-0256 | 9/8/03 | FPC - Hines Energy Complex | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| FL-0265 | 6/8/05 | Progress Energy - Hines Power Block 4 | SCR | 2.5 | ppm | |
| GA | 3/24/03 | GenPower Rincon | SCR | 2.5 | ppm | |
| GA | 4/17/03 | Savannah Electric and Power - Plant McIntosh | SCR | 2.5 | ppm | |
| GA-0105 | 4/17/03 | McIntosh Combined Cycle Facility | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppm | BACT |
| GA-0138 | 4/8/10 | Live Oaks Power Plant | SCR, Dry Low $NO_x$ Burners | 2.5 | ppm | BACT |
| ME | 12/4/98 | Westbrook Power LLC | SCR | 2.5 | ppm | LAER |
| MI-0366 | 4/13/2005 | Berrien Energy LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| NC-0094 | 1/9/02 | GenPower Earleys, LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| NC-0095 | 5/28/02 | Mirant Gastonia | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| NC-0101 | 9/29/05 | Forsyth Energy Projects, LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppm | BACT |
| NC | | Progress Energy Carolinas | SCR | 2.5 | ppm | |
| NH-0011 | 4/26/99 | AES Londonderry, LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| NH-0012 | 4/26/99 | Newington Energy LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | BACT |
| NJ-0043 | 3/28/02 | Liberty Generating Station | SCR | 2.5 | ppmvd | Other |
| NY | | Trigen-Nassau Energy Corp | SCR | 2.5 | ppm | |
| OR | 7/3/02 | Summit Westward - Westward Energy LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | |
| OR-0035 | 1/16/02 | Port Westward - Portland General Electric | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppm | BACT |
| OR-0039 | 12/30/03 | California Oregon Border - Peoples Energy | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| OR-0040 | 3/12/03 | Klamath Generation LLC - Pacific Power Energy Marketing | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| PA-0160 | 10/10/00 | Calpine Construction Finance Co. | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | LAER |
| PA-0188 | 3/28/02 | Fairless Energy LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmv | LAER |
| PA-0189 | 1/16/02 | Connectiv - Bethlehem North | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | LAER |
| PA-0223 | 1/30/02 | Duke Energy Fayette, LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | LAER |
| SC | 5/28/02 | Jasper County Generating Facility | SCR | 2.5 | ppm | |
| VA-0261 | 9/6/02 | CPV Cunningham Creek | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppm | BACT |
| VA-0262 | 12/6/02 | Mirant Airside Industrial Park | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| VA-0287 | 12/1/03 | James City Energy Park | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| VA-0289 | 2/5/04 | Duke Energy Wythe, LLC | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| WA | 6/19/03 | Frederickson Power II - West Coast Energy | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | |
| WA | 9/20/02 | Cliffs Energy Project - GNA Energy | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | |
| WA-0288 | 9/4/01 | Longview Energy Development | SCR | 2.5 | ppmv | BACT |
| WA-0291 | 1/3/03 | Wallula Power - Newport Northwest Generation | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| WA-0328 | 1/11/05 | BP West Coast Products LLC, BP Cherry Point Cogeneration Project | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppmvd | BACT |
| WY-0061 | 4/4/03 | Black Hills Corp - Neil Simpson Two | SCR, Dry Low $NO_x$ Combustion | 2.5 | ppm | BACT |
| AZ | | Reliant Energy - Desert Basin Generating Project | SCR | 3 | ppm | |
| CO-0052 | 8/11/02 | Rocky Mountain Energy Center | SCR, Dry Low $NO_x$ Combustion | 3.0 | ppm | BACT |
| CO-0056 | 5/2/06 | Calpine - Rocky Mountain Energy Center, LLC | SCR, Dry Low $NO_x$ Combustion | 3.0 | ppm | BACT |
| DE-0016 | 10/17/00 | Hay Road Power Complex Units 5-8 | SCR, Dry Low $NO_x$ Combustion | 3 | ppmv | LAER |
| GA | 1/15/02 | Oglethorpe Power Corp - Wansley | SCR | 3.0 | ppm | |
| GA-0101 | 10/23/02 | Murray Energy Facility | SCR, Dry Low $NO_x$ Combustion | 3 | ppm | BACT |
| GA-0102 | 1/15/02 | Wansley Combined Cycle Energy Facility | SCR, Dry Low $NO_x$ Combustion | 3 | ppm | BACT |
| IA | 7/23/02 | Hawkeye Generation, LLC | SCR, Dry Low $NO_x$ Combustion | 3 | ppm | |
| IA | 12/20/02 | Interstate Power and Light - Exira Station | SCR, Dry Low $NO_x$ Combustion | 3 | ppm | |
| IA-0058 | 4/10/02 | MidAmerican Energy, Des Moines Power Station | SCR, Dry Low $NO_x$ Combustion | 3 | ppm | BACT |
| IN-0085 | 6/7/01 | PSEG Lawrenceburg Energy Facility | SCR | 3 | ppmv | BACT |

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| IN-0086 | 5/9/01 | Mirant Sugar Creek LLC | SCR | 3 | ppmv | BACT |
| IN-0114 | 7/24/02 | Mirant Sugar Creek LLC | SCR, Dry Low $NO_x$ Combustion | 3 | ppmvd | BACT |
| LA | 6/6/2005 | Crescent City Power LLC | SCR/Low Nox Burners | 3 | ppm | |
| MI-0357 | 2/4/03 | Kalkaska Generating LLC | SCR, Dry Low $NO_x$ Combustion | 3 | ppmvd | BACT |
| MI-0361 | 1/30/03 | South Shore Power LLC | SCR, Dry Low $NO_x$ Combustion | 3 | ppmvd | BACT |
| MN-0054 | 7/15/04 | Fairbault Energy Park | SCR, Dry Low $NO_x$ Combustion | 3 | ppmvd | BACT |
| NJ-0066 | 2/16/06 | AES Red Oak LLC | SCR, Dry Low $NO_x$ Combustion | 3.0 | ppmvd | LAER |
| NJ | | Tosco Bayway Refinery Cogen Project | DLN | 3 | ppm | |
| NY-0100 | 6/23/05 | Empire Generating CO. LLC - Empire Power Plant - with duct burner | SCR, Dry Low $NO_x$ Combustion | 3.0 | ppmvd | LAER |
| OH-0252 | 12/28/04 | Duke Energy Hanging Rock Energy Facility | SCR, Dry Low $NO_x$ Combustion | 3.0 | ppm | BACT |
| PA | | SWEC Falls Township, PA | SCR | 3 | ppm | |
| VA | 4/30/02 | Tenaska Bear Garden | SCR | 3.0 | ppm | |
| VA-0256 | 1/20/02 | Tenaska Fluvanna | SCR | 3.0 | ppm | BACT |
| VA-0260 | 5/1/02 | Henry County Power | SCR, Dry Low $NO_x$ Combustion | 3.0 | ppm | BACT |
| AR-0035 | 8/24/00 | Panda - Union Generating Station | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| AR-0040 | 12/29/00 | Duke Energy Hot Springs | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| AR-0051 | 4/1/02 | Duke Energy - Jackson Facility | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppm | BACT |
| AR-0070 | 8/23/02 | Genova Arkansas I, LLC | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmvd | BACT |
| FL-0214 | 2/5/01 | CPV Gulfcoast Power Generating STN | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| FL-0239 | 3/27/02 | Jacksonville Electric Authority - Brandy Branch | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmvd | BACT |
| GA | | Live Oaks Co LLC | SCR/DLN | 3.5 | ppm | |
| IL | | Holland Energy | SCR | 3.5 | ppm | |
| MI-0267 | 6/7/01 | Renaissance Power LLC | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| MI-0365 | 1/28/03 | Mirant Wyandotte LLC | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| MS | 6/24/02 | Crossroads Energy Center | SCR | 3.5 | ppm | |
| MS-0055 | 6/24/02 | El Paso Merchant Energy CO. | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| MS-0073 | 11/23/04 | Reliant Energy Choctaw County, LLC | SCR | 3.5 | ppmv | BACT |
| MS-0059 | 9/24/02 | Pike Generation Facility | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| NC-0086 | 1/10/02 | Fayetteville Generation | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmvd | BACT |
| NE-0023 | 5/29/03 | Nebraska Public Power District - Beatrice Power Station | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppm | BACT |

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| NV-0033 | 8/19/04 | El Dorado Energy, LLC - turbine only | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppm | BACT |
| NV | 10/16/04 | Nevada Power Co. | SCR | 3.5 | ppm | |
| OH | | Dresden Energy | SCR | 3.5 | ppm | |
| OH | | PS&G Waterford Energy | SCR | 3.5 | ppm | |
| OK-0036 | 12/10/01 | Stephens Energy Facility | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| OK-0043 | 10/22/01 | Webers Falls Energy Facility | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| OK-0070 | 6/13/02 | Genova OK I Power Project | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmvd | BACT |
| OK-0090 | 3/21/03 | Duke Energy Stephens, LLC | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppm | BACT |
| OK-0096 | 6/6/03 | Redbud Power Plant | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmvd | BACT |
| OK-0115 | 12/12/06 | Energetix - Lawton Energy Cogen Facility | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmvd | BACT |
| TN-0144 | 2/1/02 | Haywood Energy Center (Calpine) | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppm | BACT |
| TX | 12/13/02 | Steag (Brazos Valley) | SCR | 3.5 | ppm | |
| VA | 6/1/02 | CPV FLUVANNA | SCR | 3.5 | ppm | |
| VA-0255 | 11/18/02 | VA Power - Possum Point | Water Injection, SCR | 3.5 | ppmvd | LAER |
| WI-0174 | 9/20/00 | Badger Generating Co LLC | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| WV-0014 | 12/18/01 | Panda Culloden Generating Station | SCR, Dry Low $NO_x$ Combustion | 3.5 | ppmv | BACT |
| NV-0033 | 8/19/04 | El Dorado Energy, LLC - with duct burner | SCR, Dry Low $NO_x$ Combustion | 3.7 | ppm | BACT |
| LA-0224 | 3/20/08 | Southwest Electric Power Company - Arsenal Hill Power Plant | SCR, Dry Low $NO_x$ Combustion | 4.0 | ppmvd | BACT |
| KS | 2/7/02 | Duke Energy - Leavenworth County | SCR, Dry Low $NO_x$ Combustion | 4.5 | ppm | |
| LA-0157 | 3/8/02 | Perryville Power Station | SCR, Dry Low $NO_x$ Combustion | 4.5 | ppm | BACT |
| MI-0363 | 1/7/03 | Bluewater Energy Center LLC | SCR, Dry Low $NO_x$ Combustion | 4.5 | ppmv | BACT |
| LA-0136 | 7/23/08 | Dow Chemical Company - Plaquemine Cogeneration Facility | SCR, Dry Low $NO_x$ Combustion | 5.0 | ppmvd | BACT |
| TX | 10/8/03 | TX Petrochem | SCR | 5.0 | ppm | |
| TX | 7/23/02 | Duke Energy | SCR | 5.0 | ppm | |
| TX-0407 | 12/6/02 | Steag-Stearne | SCR, Dry Low $NO_x$ Combustion | 5.0 | ppm | |
| LA | | Formosa Plastics Corp. - Baton Rouge | DLN | 9 | ppm | |
| OK-0117 | 2/9/07 | Public Service Company of Oklahoma - Southwestern Power Plant | SCR, Dry Low $NO_x$ Combustion | 9.0 | ppm | BACT |
| OK-0056 | 2/12/02 | Horseshoe Energy Project | SCR | 12.5 | ppm | BACT |
| FL-0285 | 1/26/07 | Progress Energy - Bartow Power Plant | Water Injection | 15.0 | ppmvd | BACT |
| TN | | TVA Lagoon Creek Plant | SCR | 15 | ppm | |
| TX-0234 | 1/8/02 | Edinburg Energy Limited Partnership | | 15 | ppm | BACT |

CTG/HRSG BACT $NO_x$ Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| TX-0374 | 3/24/03 | Chocolate Bayou Plant - BP Amoco Chemical Co | SCR, Dry Low $NO_x$ Combustion | 11.43 | lb/hour | BACT |
| LA-0120 | 2/26/02 | Shell Chemical LP - Geismar Plant | SCR, Dry Low $NO_x$ Combustion | 14.5 | lb/hour | BACT |
| OH-0264 | 5/23/04 | Norton Energy Storage, LLC | SCR, Dry Low $NO_x$ Combustion | 16 | lb/hour | BACT |
| NM-0044 | 6/27/04 | Clovis Energy Facility - Duke energy Curry LLC | SCR | 24.6 | lb/hour | BACT |
| MT-0019 | 6/7/02 | Continental Energy Services Inc. - Silver Bow Gen | SCR | 25.2 | lb/hour | BACT |
| OH-0248 | 9/24/02 | Lawrence Energy - Calpine Corporation | SCR, Dry Low $NO_x$ Combustion | 30.5 | lb/hour | BACT |
| TX-0352 | 12/31/02 | Brazos Valley Electric Generating Facility | SCR | 32.4 | lb/hour | BACT |
| MN | | Pleasant Valley | DLN, WI | 35 | ppm | |
| TX-0411 | 3/26/02 | Amelia Energy Center | SCR | 36.8 | lb/hour | |
| TX-0502 | 6/5/06 | Nacogdoches Power LLC | DLN, SCR | 45.4 | lb/hour | BACT |
| TX-0388 | 2/12/02 | Sand Hill Energy Center - Austin Electric Utility | | 46 | lb/hour | BACT |
| TX-0350 | 1/31/02 | Ennis Tractebel Power | SCR, Dry Low $NO_x$ Combustion | 61.8 | lb/hour | BACT |
| TX-0391 | 12/20/02 | Oxy Cogeneration Facility - Oxy Vinyls LP | SCR | 115 | lb/hour | BACT |
| OK-0055 | 2/12/02 | Mustang Energy Project | SCR | 48.49 | tons/year | BACT |

Table contains:
Entries from the EPA turbine spreadsheet with a permit issuance date in 2002 - 2012
Entries from the RBLC for new units with a permit issuance date after 2002
Information from state agency websites

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| CT-0151 | 2/25/08 | Kleen Energy Systems, LLC - turbine only | Oxidation Catalyst | 0.9 | ppmvd | BACT | 1-hour block, no duct firing |
| CA-1192 | 6/21/11 | Avenal Power Center LLC | Oxidation Catalyst | 1.5 | ppmvd | BACT | 1-hour average, no duct firing, does not apply during first three years of operation |
| CA-1212 | 10/18/11 | Palmdale Hybrid Power Project | Oxidation Catalyst | 1.5 | ppmvd | BACT | 1-hour, no duct firing, does not apply during 3-year demonstration period |
| VA | 3/12/13 | Virginia Electric and Power Company - Warren County Power Plant - Brunswick - without duct burners | Oxidation Catalyst, Good Combustion Practices | 1.5 | ppmvd | BACT | 1-hour average, no duct firing |
| VA-0315 | 12/17/10 | Virginia Electric and Power Company - Warren County Power Plant - Dominion - without duct burners | Oxidation Catalyst, Good Combustion Practices | 1.5 | ppmvd | BACT | 1-hour average, no duct firing |
| CT-0151 | 2/25/08 | Kleen Energy Systems, LLC - with duct burner | Oxidation Catalyst | 1.7 | ppmvd | BACT | 1-hour block |
| GA-0127 | 1/7/08 | Southern Company/Georgia Power - Plant McDonough | Oxidation Catalyst | 1.8 | ppm | BACT | 3-hour |
| CA | 5/27/2003 | Magnolia Power Project | Oxidation Catalyst | 2 | ppm | | |
| CA | | City of Victorville | Oxidation Catalyst | 2 | ppm | w/o duct burners | |
| CA | 6/2/2011 | Oakley Generating Station | Oxidation Catalyst | 2 | ppm | | |
| CA | | Sunlaw Cogen Partners | | 2 | ppm | | |
| CA-1050 | 9/11/00 | IDC Bellingham | Oxidation Catalyst | 2.0 | ppm | | |
| CA-1096 | 2/1/2004 | Vernon City Power & Light | Oxidation Catalyst | 2 | ppm | | |
| CA-1191 | 3/11/10 | Victorville 2 Hybrid Power Project | Oxidation Catalyst | 2.0 | ppmvd | BACT | 1-hour average, no duct firing |
| CA-1192 | 6/21/11 | Avenal Power Center LLC | Oxidation Catalyst | 2.0 | ppmvd | BACT | 1-hour average |
| CA-1212 | 10/18/11 | Palmdale Hybrid Power Project | Oxidation Catalyst | 2.0 | ppmvd | BACT | 1-hour |
| CT-0148 | 6/22/99 | Lake Road Generating Company | Oxidation Catalyst | 2 | ppmv | BACT | |
| GA | 5/30/12 | Effingham County Power Plant | Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| GA | 4/17/03 | Savannah Electric and Power - Plant McIntosh | Oxidation Catalyst | 2.0 | ppm | | |
| GA | 3/24/03 | GenPower Rincon | Oxidation Catalyst | 2.0 | ppm | | |
| GA | 1/15/02 | Oglethorpe Power Corp - Wansley | Oxidation Catalyst | 2.0 | ppm | | |
| GA-0102 | 1/15/02 | Wansley Combined Cycle Energy Facility | Good Combustion Practices | 2 | ppm | BACT | |
| GA-0105 | 4/17/03 | McIntosh Combined Cycle Facility | Oxidation Catalyst | 2 | ppm | BACT | |

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| GA-0138 | 4/8/10 | Live Oaks Power Plant - without duct firing | Good Combustion Practices, Catalytic Oxidation | 2.0 | ppm | BACT | |
| ID-0018 | 6/25/10 | Idaho Power Company - Langley Gulch Power Plant | Catalytic Oxidation, DLN, Good Combustion Practices | 2.0 | ppmvd | BACT | |
| IN-0158 | 12/3/12 | St. Joseph Energy Center LLC | Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| MA | 2/22/1999 | Cabot Power Island Cogeneraton Project | Oxidation Catalyst | 2 | ppm | | |
| MA | 12/14/2006 | Fore River Station Weymouth | Oxidation Catalyst | 2 | ppm | | |
| MA-0029 | 1/25/00 | Sithe Mystic Development | Oxidation Catalyst | 2.0 | ppm | BACT | |
| MI-0366 | 4/13/2005 | Berrien Energy LLC | Oxidation Catalyst | 2.0 | ppm | BACT | |
| NJ | 9/13/12 | Hess Newark Energy Center | Oxidation Catalyst | 2 | ppmvd | BACT | |
| NJ | 5/31/12 | Woodbridge Energy Center | Oxidation Catalyst | 2 | ppmvd | BACT | |
| NJ-0043 | 3/28/02 | Liberty Generating Station | Oxidation Catalyst | 2 | ppmvd | Other | |
| NY | 9/27/12 | Cricket Valley Energy Center LLC | Good Combustion Controls and Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| NY-0095 | 5/10/06 | Caithness Bellport, LLC | Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| OH-0352 | 6/18/13 | Oregon Clean Energy Center | Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| OR | 1/6/2005 | Turner Energy Center LLC | Oxidation Catalyst | 2 | ppm | >70% load | |
| OR-0039 | 12/30/03 | California Oregon Border - Peoples Energy | Oxidation Catalyst | 2 | ppmvd | BACT | |
| OR-0041 | 8/8/05 | Diamond Wanapa I, L. P. - Wanapa Energy Center | Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| PA-0286 | 1/13/13 | Moxie Energy LLC/Patriot Energy Plant | CO Catalyst | 2.0 | ppmvd | BACT | |
| PA-0291 | 4/23/13 | Hickory Run Energy LLC | CO Catalyst | 2.0 | ppmvd | Other | |
| TX-0546 | 6/7/09 | Pattillo Branch Power Company LLC | Oxidation Catalyst | 2 | ppmvd | BACT | |
| TX-0590 | 8/5/10 | Pondera Capital Management GP INC - King Power Station | Oxidation Catalyst, Good Combustion Practices | 2.0 | ppmvd | BACT | |
| VA | 4/30/13 | Stonewall, LLC | Good Combustion Control and Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| VA-0261 | 9/6/02 | CPV Cunningham Creek | Oxidation Catalyst | 2 | ppm | BACT | |
| WA | 6/19/03 | Frederickson Power II - West Coast Energy | Oxidation Catalyst | 2.0 | ppmvd | | |
| WA | 4/20/03 | Plymouth Generating Facility | Oxidation Catalyst | 2 | ppmvd | | |
| WA-0288 | 9/4/01 | Longview Energy Development | Oxidation Catalyst | 2 | ppmvd | BACT | |
| WA-0291 | 1/3/03 | Wallula Power - Newport Northwest Generation | Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| WA-0299 | 4/17/03 | Sumas Energy 2 - NESCO | Oxidation Catalyst | 2.0 | ppmvd | BACT - Project Cancelled | |
| WA-0328 | 1/11/05 | BP West Coast Products LLC, BP Cherry Point Cogeneration Project | Oxidation Catalyst | 2.0 | ppmvd | BACT | |
| WI-0114 | 1/13/95 | LS Power | Oxidation Catalyst | 2 | ppmv | BACT | |

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| VA | 3/12/13 | Virginia Electric and Power Company - Warren County Power Plant - Brunswick - without duct burners | Oxidation Catalyst, Good Combustion Practices | 2.4 | ppmvd | BACT | |
| VA-0315 | 12/17/10 | Virginia Electric and Power Company - Warren County Power Plant - Dominion -with duct burners | Oxidation Catalyst, Good Combustion Practices | 2.4 | ppmvd | BACT | |
| PA-0189 | 1/16/02 | Connectiv - Bethlehem North | Good Combustion Practices | 2.5 | ppm | BACT | |
| NV | 10/16/2004 | Nevada Power Co. | Oxidation Catalyst | 2.6 | ppm | | |
| NV-0033 | 8/19/04 | El Dorado Energy, LLC - turbine only | Oxidation Catalyst | 2.6 | ppm | LAER | |
| AZ-0039 | 3/7/03 | Salt River Project/Santan Gen. Plant | Oxidation Catalyst | 3 | ppm | LAER | |
| AZ-0043 | 11/12/03 | Duke Energy Arlington Valley | Oxidation Catalyst | 3 | ppm | BACT | |
| AZ-0047 | 12/1/2004 | Dome Valley Energy Partners, LLC - Wellton Mohawk Generating Station | Oxidation Catalyst | 3.0 | ppmv | BACT | |
| CA | | City of Victorville | Oxidation Catalyst | 3 | ppm | w/ duct burners | |
| CA-1191 | 3/11/10 | Victorville 2 Hybrid Power Project | Oxidation Catalyst | 3.0 | ppmvd | BACT | |
| CA-1211 | 3/11/11 | Colusa Generating Station | Catalytice Oxidation System | 3.0 | ppmvd | BACT | |
| CO-0056 | 5/2/06 | Calpine - Rocky Mountain Energy Center, LLC | Oxidation Catalyst | 3.0 | ppm | BACT | |
| LA-0254 | 8/16/11 | Ninemile Point Electric Generating Plant Units 6A and 6B | Oxidation Catalyst, Good Combustion Practices | 3.0 | ppmvd | BACT | |
| MA | 4/16/1999 | ANP Blackstone | Oxidation Catalyst | 3 | ppm | | |
| MA | | ANP Bellingham | Oxidation Catalyst | 3 | ppm | | |
| MI | 2/8/99 | Wyandotte Energy | Oxidation Catalyst | 3.0 | ppm | LAER | |
| MI-0267 | 6/7/01 | Renaissance Power LLC | Oxidation Catalyst | 3.0 | ppmv | BACT | |
| NV-0037 | 5/14/04 | Sempra Energy Resources - Copper Mountain Power | Oxidation Catalyst | 3.0 | ppmvd | LAER | |
| OR | 1/6/2005 | Turner Energy Center LLC | Oxidation Catalyst | 3 | ppm | <70% load | |
| PA | | SWEC Falls Township | | 3 | ppm | | |
| PA-0188 | 3/28/02 | Fairless Energy LLC | Oxidation Catalyst | 3 | ppmvd | BACT | |
| UT | | Summit Valley | Oxidation Catalyst | 3 | ppm | | |
| UT-0066 | 5/17/04 | Pacificorp - Currant Creek Power Project | Oxidation Catalyst | 3.0 | ppm | | |
| GA-0138 | 4/8/10 | Live Oaks Power Plant - with duct firing | Good Combustion Practices, Catalytic Oxidation | 3.2 | ppm | BACT | |
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 5 - turbine only | Oxidation Catalyst | 3.2 | lb/hour | BACT | |
| NV-0033 | 8/19/04 | El Dorado Energy, LLC - with duct burner | Oxidation Catalyst | 3.5 | ppm | LAER | |
| NV-0035 | 8/16/05 | Sierra Pacific Power Company - Tracy Substation Expansion Project | Oxidation Catalyst | 3.5 | ppm | BACT | |

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| MI-0365 | 1/28/03 | Mirant Wyandotte LLC | Oxidation Catalyst | 3.8 | ppm | BACT | |
| AZ-0033 | 3/22/01 | Mesquite Generating Station | Oxidation Catalyst | 4.0 | ppmv | BACT | |
| AZ-0038 | 4/30/02 | Gila Bend Power Generation Station | | 4 | ppm | BACT | |
| CA | 12/1/2008 | Russell City Energy Center | Oxidation Catalyst | 4 | ppm | BACT-CA | |
| CA | 8/1/2006 | San Joaquin Valley Energy Center | Oxidation Catalyst | 4 | ppm | BACT-CA | |
| CA | 12/1/2002 | Palomar Escondido - Sempra | Oxidation Catalyst | 4 | ppm | BACT-CA | |
| CA | 12/18/01 | Elk Hills Power Project | Oxidation Catalyst | 4.0 | ppmv | BACT-CA | |
| CA | 5/21/01 | Three Mountain Power | | 4.0 | ppm | BACT-CA | |
| CA | 12/1/2000 | Sutter Power Project | Oxidation Catalyst | 4 | ppm | BACT-CA | |
| CA-0997 | 9/1/03 | Sacramento Municipal Utility District | Good Combustion Control | 4 | ppm | LAER | |
| CA-1143 | 8/16/04 | Calpine Corporation - Sutter Power Plant | Oxidation Catalyst | 4.0 | ppmvd | BACT-CA | |
| CA-1144 | 4/25/07 | Caithness Blythe II, LLC | | 4.0 | ppmvd | BACT-CA | |
| CA-1209 | 3/11/10 | High Desert Power Project LLC | Oxidation Catalyst | 4.0 | ppmvd | BACT | |
| LA | 6/6/2005 | Crescent City Power LLC | Oxidation Catalyst & good combustion | 4 | ppm | | |
| MI-0361 | 1/30/03 | South Shore Power LLC | Oxidation Catalyst | 4 | ppmvd | BACT | |
| NJ | | Tosco Bayway Refinery Cogen Project | | 4 | ppm | | |
| NJ-0066 | 2/16/06 | AES Red Oak LLC | Oxidation Catalyst | 4.0 | ppmvd | BACT | |
| NV-0038 | 6/28/05 | Ivanpah Energy Center, L.P. | Good Combustion Practice, Oxidation Catalyst | 4.0 | ppmvd | LAER | |
| OR | 7/3/02 | Summit Westward - Westward Energy LLC | Good Combustion Practices | 4 | ppmvd | | |
| TX-0600 | 9/1/11 | Thomas C. Ferguson Power Plant | Oxidation Catalyst, Good Combustion Practices | 4.0 | ppmvd | BACT | |
| TX-0618 | 10/24/12 | Channel Energy Center LLC | Good Combustion | 4.0 | ppmvd | BACT | |
| TX-0619 | 9/26/12 | Deer Park Energy Center | Good Combustion | 4.0 | ppmvd | BACT | |
| TX-0620 | 9/12/12 | ES Joslin Power Plant | Good Combustion | 4.0 | ppmvd | BACT | |
| UT | | Calpine - Vineyard Energy Center LLC | Oxidation Catalyst | 4 | ppm | | |
| WA | 9/20/02 | Cliffs Energy Project - GNA Energy | Oxidation Catalyst | 4 | ppmvd | | |
| WI-0174 | 9/20/00 | Badger Generating Co LLC | Oxidation Catalyst | 4 | ppmv | BACT | |
| OR-0035 | 1/16/02 | Port Westward - Portland General Electric | Oxidation Catalyst | 4.9 | ppmvd | BACT | |
| IA | 12/20/02 | Interstate Power and Light - Exira Station | Oxidation Catalyst | 5 | ppm | | |
| IA | 7/23/02 | Hawkeye Generation, LLC | Oxidation Catalyst | 5 | ppm | | |
| IA-0058 | 4/10/02 | MidAmerican Energy, Des Moines Power Station | Oxidation Catalyst | 5 | ppm | BACT | |
| MI-0256 | 1/12/01 | Covert Generating Co LLC | Oxidation Catalyst | 5.0 | ppmv | BACT | |
| MI-0357 | 2/4/03 | Kalkaska Generating LLC | Oxidation Catalyst | 5 | ppmvd | BACT | |
| OR-0040 | 3/12/03 | Klamath Generation LLC - Pacific Power Energy Marketing | Oxidation Catalyst | 5.0 | ppmvd | BACT | |
| PA-0223 | 1/30/02 | Duke Energy Fayette, LLC | Oxidation Catalyst | 5 | ppm | BACT | |
| CA | 12/1/2004 | La Paloma PG&E | Oxidation Catalyst | 6 | ppm | | |
| CA | 11/9/2004 | Los Medanos Energy Center | Oxidation Catalyst | 6 | ppm | | |

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| CA | 9/1/01 | Metcalf Energy Center | | 6.0 | ppm | | |
| CA | 5/30/01 | Contra Costa | Oxidation Catalyst | 6.0 | ppmv | BACT-CA | |
| CA | 3/1/01 | Western Midway Sunset Power Project | Oxidation Catalyst | 6.0 | ppm | BACT-CA | |
| CA | | Texaco Global - Sunrise Cogeneration | | 6 | ppm | | |
| CA-1142 | 12/23/04 | Calpine Western Regional Office - Pastoria Energy Facility | Oxidation Catalyst | 6.0 | ppmvd | BACT-CA | |
| CA-1177 | 9/12/11 | Otay Mesa | Oxidation Catalyst | 6.0 | ppmv | BACT -CA | |
| CA-1213 | 3/1/01 | Mountainview Power Project | Oxidation Catalyst | 6.0 | ppm | BACT-CA | |
| FL-0280 | 5/30/06 | Florida Municipal Power Agency - Treasure Coast Energy Center | Good Combustion | 6.0 | ppm | BACT | |
| FL-0304 | 9/8/08 | Florida Municipal Power Agency - Cane Island Power Park | Good Combustion Practices | 6.0 | ppmvd | BACT | |
| IN-0085 | 6/7/01 | PSEG Lawrenceburg Energy Facility | Good Combustion | 6 | ppmv | BACT | |
| OH-0252 | 12/28/04 | Duke Energy Hanging Rock Energy Facility - turbine only | | 6.0 | ppm | BACT | |
| OR | 1/18/02 | Umatilla Generating - PG&E | Oxidation Catalyst | 6.0 | ppmvd | | |
| FL-0225 | 8/17/01 | El Paso Broward Energy Center | Combustion Controls | 7.4 | ppmv | BACT | |
| FL-0226 | 9/11/01 | El Paso Manatee Energy Center | Combustion Controls | 7.4 | ppmv | BACT | |
| FL-0227 | 9/7/01 | El Paso Belle Glade Energy Center | Combustion Controls | 7.4 | ppmv | BACT | |
| TN-0144 | 2/1/02 | Haywood Energy Center (Calpine) | Good Combustion Practices | 7.4 | ppm | BACT | |
| FL-0263 | 2/8/05 | Florida Power and Light Turkey Point Power Plant | Good Combustion Practices | 7.6 | ppm | BACT | |
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 5 - with duct burner | Oxidation Catalyst | 7.6 | lb/hour | BACT | |
| OK | 1/21/00 | Oneta Generating Station | Combustion Controls | 7.8 | ppm | BACT | |
| FL-0241 | 1/17/02 | CPV Cana Power Generation Facility | Good Combustion Practices | 8 | ppmvd | BACT | |
| FL-0265 | 6/8/05 | Progress Energy - Hines Power Block 4 | Good Combustion | 8.0 | ppm | BACT | |
| FL-0285 | 1/26/07 | Progress Energy - Bartow Power Plant | Good Combustion | 8.0 | ppmvd | BACT | |
| FL-0286 | 1/10/07 | Florida Power and Light West County Energy Center | | 8.0 | ppmvd | BACT | |
| OK-0129 | 1/23/09 | Associated Electric Cooperative Inc - Chouteau Power Plant | Good Combustion | 8.0 | ppmv | BACT | |
| AR-0070 | 8/23/02 | Genova Arkansas I, LLC | Good Combustion Practices | 8.2 | ppmvd | BACT | |
| OK-0070 | 6/13/02 | Genova OK I Power Project | Combustion Controls | 8.2 | ppm | BACT | |
| WV-0014 | 12/18/01 | Panda Culloden Generating Station | Good Combustion | 8.2 | ppmv | BACT | |
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 4 - turbine only | Oxidation Catalyst | 8.4 | lb/hour | BACT | |
| CA | 12/1/2002 | Pastoria Energy LLC | Oxidation Catalyst | 9 | ppm | BACT-CA | |
| CO | 6/19/00 | Fort St. Vrain | Combustion Controls | 9.0 | ppm | BACT | |
| CO-0052 | 8/11/02 | Rocky Mountain Energy Center | Oxidation Catalyst | 9 | ppmvd | BACT | |
| DE-0016 | 10/17/00 | Hay Road Power Complex Units 5-8 | Good Combustion | 9 | ppmv | BACT | |

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| FL | 1/9/02 | TECO Bayside Power Station (repowering) | Good Combustion Practices | 9.0 | ppm | | |
| FL-0214 | 2/5/01 | CPV Gulfcoast Power Generating STN | Combustion Controls | 9 | ppmv | BACT | |
| FL-0223 | 11/4/99 | Lake Worth Generating, LLC | Combustion Design | 9 | ppmv | BACT | |
| IN-0086 | 5/9/01 | Mirant Sugar Creek LLC | Good Combustion | 9 | ppmv | BACT | |
| IN-0087 | 6/6/01 | Duke Energy, Vigo LLC | Good Combustion | 9.0 | ppmv | BACT | |
| IN-0114 | 7/24/02 | Mirant Sugar Creek LLC | Good Combustion Practices | 9 | ppmvd | BACT | |
| ME | 9/14/98 | Champion Intl Corp. & Champ. Clean Energy | | 9.0 | ppm | BACT | |
| MN-0071 | 6/5/07 | Minnesota Municipal Power Agency - Fairbault Energy Park - turbine only | Good Combustion | 9.0 | ppmvd | BACT | |
| NC-0086 | 1/10/02 | Fayetteville Generation | Good Combustion Practices | 9 | ppm | BACT | |
| NC-0094 | 1/9/02 | GenPower Earleys, LLC | Good Combustion Practices | 9 | ppm | BACT | |
| NC-0095 | 5/28/02 | Mirant Gastonia | Good Combustion Practices | 9 | ppm | BACT | |
| NY | | Trigen Nassau Energy Corp. | | 9 | ppm | | |
| OH-0252 | 12/28/04 | Duke Energy Hanging Rock Energy Facility - with duct burner | | 9.0 | ppm | BACT | |
| SC | 5/28/02 | Jasper County Generating Facility | Good Combustion Practices | 9 | ppm | | |
| VA-0287 | 12/1/03 | James City Energy Park | Good Combustion Practices | 9.0 | ppm | BACT | |
| VA-0289 | 2/5/04 | Duke Energy Wythe, LLC - turbine only | Good Combustion Practices | 9 | ppmvd | BACT | |
| OH-0248 | 9/24/02 | Lawrence Energy - Calpine Corporation | Oxidation Catalyst | 9.8 | lb/hour | BACT | |
| AL-0185 | 7/12/02 | Barton Shoals Energy, LLC | Good Combustion Practices | 10.0 | ppm | BACT | |
| CA | 2/1/02 | Delta Energy Center | | 10.0 | ppm | | |
| FL-0202 | 8/17/92 | Orlando Cogen | Combustion Controls | 10 | ppmv | BACT | |
| FL-0244 | 4/16/03 | FPL Martin | Good Combustion Practices | 10 | ppmvd | BACT | |
| FL-0245 | 4/15/03 | FPL Manatee - Unit 3 | Good Combustion Practices | 10 | ppmvd | BACT | |
| FL-0256 | 9/8/03 | FPC - Hines Energy Complex | Good Combustion Practices | 10 | ppmvd | BACT | |
| LA-0224 | 3/20/08 | Southwest Electric Power Company - Arsenal Hill Power Plant | Proper Operating Practices | 10.0 | ppmvd | BACT | |
| MN-0053 | 7/15/04 | Fairbault Energy Park | Good Combustion Practices | 10 | ppmvd | BACT | |
| MN-0060 | 8/12/05 | Northern States Power Co. DBA XCEL Energy - High Bridge Generating Plant - turbine only | Good Combustion Practices | 10.0 | ppm | BACT | |
| MN-0066 | 5/16/06 | Northern States Power Co. DBA XCEL Energy - Riverside Plant | Good Combustion Practices | 10.0 | ppm | BACT | |
| MO-0049 | 8/19/99 | Kansas City Power & Light | Oxidation Catalyst | 10 | ppmv | BACT | |
| MO-0056 | 3/30/99 | Associated Electric Cooperative, Inc. | Good Combustion | 10 | ppmv | BACT | |
| NC | | Progress Energy - Carolinas | GCP | 10 | ppm | | |
| OK | 3/24/99 | Chouteau Power Plant | Combustion Controls | 10.0 | ppm | BACT | |
| OK-0036 | 12/10/01 | Stephens Energy Facility | | 10.0 | ppmv | BACT | |
| OK-0043 | 10/22/01 | Webers Falls Energy Facility | Combustion Controls | 10 | ppmv | BACT | |
| OK-0090 | 3/21/03 | Duke Energy Stephens, LLC | Combustion Controls | 10 | ppm | BACT | |

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| PA-0160 | 10/10/00 | Calpine Construction Finance Co. | | 10.0 | ppmv | BACT | |
| PA-0226 | 4/9/02 | Limerick Partners, LLC | | 10 | ppm | BACT | |
| VA-0262 | 12/6/02 | Mirant Airside Industrial Park | Good Combustion Practices | 10.3 | ppmvd | BACT | |
| MS | 6/24/02 | Crossroads Energy Center | Good Combustion Practices | 10.4 | ppm | | |
| NE-0023 | 5/29/03 | Nebraska Public Power District - Beatrice Power Station | Oxidation Catalyst | 10.8 | lb/hour | BACT | |
| MN-0071 | 6/5/07 | Minnesota Municipal Power Agency - Fairbault Energy Park - with duct burner | Good Combustion | 11.0 | ppmvd | BACT | |
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 4 - with duct burner | Oxidation Catalyst | 11.5 | lb/hour | BACT | |
| NC-0101 | 9/29/05 | Forsyth Energy Projects, LLC - turbine only | Good Combustion Practices | 11.6 | ppm | BACT | |
| GA-0101 | 10/23/02 | Murray Energy Facility | Good Combustion Practices | 12 | ppm | BACT | |
| FL-0239 | 3/27/02 | Jacksonville Electric Authority - Brandy Branch | Good Combustion Practices | 12.21 | ppmvd | BACT | |
| MS-0055 | 6/24/02 | El Paso Merchant Energy CO. | Good Combustion Practices | 13.8 | ppmv | BACT | |
| VA-0289 | 2/5/04 | Duke Energy Wythe, LLC - with duct burner | Good Combustion Practices | 14.6 | ppmvd | BACT | |
| TX | 10/8/03 | TX Petrochem | Good Combustion Practices | 15 | ppm | | |
| TX-0547 | 6/22/09 | Lamar Power Partners II LLC | Good Combustion Practices | 15 | ppmvd | BACT | |
| NC | | Southern Power Co. - Plant Rowan County | GCP | 16 | ppm | | |
| OK-0115 | 12/12/06 | Energetix - Lawton Energy Cogen Facility | Good Combustion Practices | 16 | ppmvd | BACT | |
| KS | 2/7/02 | Duke Energy - Leavenworth County | Good Combustion Practices | 16.9 | ppm | | |
| GA | | Live Oak Co. LLC | GCP | 17 | ppm | | |
| OK-0096 | 6/6/03 | Redbud Power Plant | Good Combustion Practices | 17.2 | ppmvd | BACT | |
| TX-0548 | 8/18/09 | Madison Bell Partners LP | Good Combustion Practices | 17.5 | ppmvd | BACT | |
| MN-0060 | 8/12/05 | Northern States Power Co. DBA XCEL Energy - High Bridge Generating Plant - with duct firing | Good Combustion Practices | 18.0 | ppm | BACT | |
| MS-0073 | 11/23/04 | Reliant Energy Choctaw County, LLC | | 18.36 | ppmv | BACT | |
| TX | 7/23/02 | Duke Energy | | 20.0 | | | |
| TX-0502 | 6/5/06 | Nacogdoches Power LLC | Good Combustion Practices | 20.2 | ppmvd | BACT | |
| VA-0256 | 1/20/02 | Tenaska Fluvanna | Good Combustion Practices | 21 | ppmvd | BACT | |
| OH-0264 | 5/23/04 | Norton Energy Storage, LLC | | 23 | lb/hour | BACT | |
| AR-0051 | 4/1/02 | Duke Energy - Jackson Facility | Good Operating Practices | 23.6 | ppm | BACT | |
| AZ | | Reliant Energy - Desert Basin Generating Project | | 24 | ppm | | |
| LA-0136 | 7/23/08 | Dow Chemical Company - Plaquemine Cogeneration Facility | Good Combustion Practices | 25.0 | ppmvd | BACT | |
| LA-0157 | 3/8/02 | Perryville Power Station | Good Operating Practices | 25.0 | ppm | BACT | |

CTG/HRSG BACT CO Comparison

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | Averaging Period |
|---|---|---|---|---|---|---|---|
| OK-0117 | 2/9/07 | Public Service Company of Oklahoma - Southwestern Power Plant | Combustion Control | 25.0 | ppmvd | BACT | |
| TX | 12/13/02 | Steag (Brazos Valley) | Good Combustion Practices | 25 | ppm | | |
| NC-0101 | 9/29/05 | Forsyth Energy Projects, LLC - with duct burner | Good Combustion Practices | 25.9 | ppm | BACT | |
| MI-0362 | 4/21/03 | Midland Cogeneration Venture Limited Partnership | Good Combustion Practices | 26 | lb/hour | BACT | |
| VA-0255 | 11/18/02 | VA Power - Possum Point | | 32 | lb/hour | BACT | |
| MN | | Pleasant Valley | GCP | 35 | ppm | | |
| AZ-0034 | 2/15/01 | Harquahala Generating Project | Oxidation Catalyst | 37 | lb/hour | BACT | |
| WY-0061 | 4/4/03 | Black Hills Corp - Neil Simpson Two | Good Combustion Practices | 37.2 | ppmvd | BACT | |
| NM-0044 | 6/27/04 | Clovis Energy Facility - Duke energy Curry LLC | Good Combustor Design | 37.6 | lb/hour | BACT | |
| MS-0059 | 9/24/02 | Pike Generation Facility | Efficient Combustion Practices | 40.0 | ppmv | BACT | |
| OK-0055 | 2/12/02 | Mustang Energy Project | Combustion Controls | 40 | ppm | BACT | |
| VA-0260 | 5/1/02 | Henry County Power | Good Combustion Practices | 41.4 | lb/hour | BACT | |
| MI-0363 | 1/7/03 | Bluewater Energy Center LLC | Catalytic Afterburner | 41.7 | lb/hour | BACT | |
| TX-0234 | 1/8/02 | Edinburg Energy Limited Partnership | | 43 | lb/hour | BACT | |
| LA-0120 | 2/26/02 | Shell Chemical LP - Geismar Plant | Good Combustion Practices | 44.0 | lb/hour | BACT | |
| CT | | PDC - El Paso Meriden | Oxidation Catalyst | 52.4 | lb/hr | | |
| TX-0391 | 12/20/02 | Oxy Cogeneration Facility - Oxy Vinyls LP | Good Combustion Practices | 64.3 | lb/hour | BACT | |
| TX-0374 | 3/24/03 | Chocolate Bayou Plant - BP Amoco Chemical Co | Good Combustion Practices | 66.81 | lb/hour | BACT | |
| TX-0352 | 12/31/02 | Brazos Valley Electric Generating Facility | Good Combustion Control | 92.4 | lb/hour | BACT | |
| TX-0388 | 2/12/02 | Sand Hill Energy Center - Austin Electric Utility | | 98.2 | lb/hour | BACT | |
| TX-0407 | 12/6/02 | Steag-Stearne | Good Combustion Practices | 109.4 | lb/hour | | |
| TX-0350 | 1/31/02 | Ennis Tractebel Power | None | 124 | lb/hour | BACT | |
| MT-0019 | 6/7/02 | Continental Energy Services Inc. - Silver Bow Gen | | 139.9 | lb/hour | Other | |
| TX-0411 | 3/26/02 | Amelia Energy Center | Good Combustion Practices | 208.0 | lb/hour | | |

Table contains:
Entries from the EPA turbine spreadsheet with a permit issuance date in 2002 - 2012
Entries from the RBLC for new units with a permit issuance date after 2002
Information from state agency websites

CTG/HRSG BACT Comparison for PM/$PM_{10}$/$PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| OK-0129 | 1/23/09 | Associated Electric Cooperative Inc - Chouteau Power Plant | Natural Gas Fuel | 6.59 | lb/hour | No duct firing |
| CA | 12/1/2008 | Russell City - Calpine | SCR, DLN, Oxidation catalyst | 7.5 | lbs/hr | BACT-CA |
| LA-0191 | 10/12/04 | Entergy New Orleans, Inc. - Michoud Electric Generating Plant - turbine only | Use of Clean Burning Fuels | 7.85 | lb/hour | BACT - no duct firing |
| CA-1144 | 4/25/07 | Caithness Blythe II, LLC | Use Public Utility Commission Quality Natural Gas with Sulfur Content less than or Equal to 05 grains/100scf | 8.0 | lb/hour | BACT-CA |
| VA-0315 | 12/17/10 | Virginia Electric and Power Company - Warren County Power Plant - Dominion -without duct burners | Natural Gas with Sulfur Content of 0.0003% by Weight | 8.00 | lb/hour | BACT - without duct burners |
| CA-1192 | 6/21/11 | Avenal Power Center LLC | Pipeline Quality Natural Gas | 8.91 | lb/hour | BACT - no duct firing |
| CA | | Delta Energy Center | | 9 | lbs/hr | |
| CA | | Duke Energy - Moss Landing | SCR, DLN | 9 | lbs/hr | |
| CA | | Los Medanos - Calpine | SCR, DLN, Oxidation catalyst | 9 | lbs/hr | |
| CA | 9/1/01 | Metcalf - Calpine | SCR, DLN, Oxidation catalyst | 9 | lbs/hr | w/o duct burner |
| CA-0997 | 9/1/03 | Sacramento Municipal Utility District | Good Combustion Control | 9 | lb/hour | LAER |
| ME | 9/14/98 | Champion Intl Corp. & Champ. Clean Energy | | 9.0 | lb/hour | BACT |
| MO | 6/19/00 | University of Missouri - Columbia | Combustion Controls | 9.0 | lb/hour | BACT |
| NV-0033 | 8/19/04 | El Dorado Energy, LLC - turbine only | | 9 | lb/hour | LAER |
| CA | 3/1/01 | Western Midway Sunset Power Project | | 9.4 | lb/hour | BACT-CA |
| OK | 1/21/00 | Oneta Generating Station | Use of Natural Gas | 9.4 | lb/hour | BACT |
| LA-0191 | 10/12/04 | Entergy New Orleans, Inc. - Michoud Electric Generating Plant - with duct burner | Use of Clean Burning Fuels | 9.77 | lb/hour | BACT |
| TX-0374 | 3/24/03 | Chocolate Bayou Plant - BP Amoco Chemical Co | Good Combustion Practices, Only Gaseous Fuels Containing No Ash | 10.03 | lb/hour | BACT |
| LA-0120 | 2/26/02 | Shell Chemical LP - Geismar Plant | Good Combustion Practices, Natural Gas | 10.8 | lb/hour | BACT |
| NE-0023 | 5/29/03 | Nebraska Public Power District - Beatrice Power Station | | 10.8 | lb/hour | BACT |
| CA-1096 | | Vernon City Power & Light | | 11 | lbs/hr | |
| CA | 1/30/2004 | Magnolia Power Project | Natural gas fuel | 11 | lbs/hr | |

CTG/HRSG BACT Comparison for $PM/PM_{10}/PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | |
|---|---|---|---|---|---|---|---|
| CA | | Inland Empire | SCR, DLN, Oxidation catalyst | 11 | lbs/hr | | |
| CA | | SCE/Mountainview 3 and 4 | SCR, DLN, Oxidation catalyst | 11 | lbs/hr | | |
| CT-0151 | 2/25/08 | Kleen Energy Systems, LLC - turbine only | | 11.0 | lb/hour | BACT | |
| FL-0241 | 1/17/02 | CPV Cana Power Generation Facility | Good Combustion, Clean Fuel | 11 | lb/hour | BACT | |
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 5 - turbine only | | 11.0 | lb/hour | BACT | |
| MI-0267 | 6/7/01 | Renaissance Power LLC | Good Combustion | 11.0 | lb/hour | BACT | |
| NJ | 9/13/12 | Hess Newark Energy Center | | 11 | lb/hour | BACT | |
| TX-0590 | 8/5/10 | King Power Station - Siemens Turbines | Low Ash Fuel | 11.1 | lb/hour | BACT | |
| NV-0038 | 6/28/05 | Ivanpah Energy Center, L.P. | Good Combustion Control, Pipeline Quality Natural Gas | 11.25 | lb/hour | LAER | |
| CA-1213 | 3/1/01 | Mountainview Power Project | | 11.5 | lb/hour | BACT-CA | |
| CA-1143 | 8/16/04 | Calpine Corporation - Sutter Power Plant | | 11.5 | lb/hour | BACT-CA | |
| CA | | San Joaquin Valley Energy Center | | 11.5 | lbs/hr | | |
| CA | | Feather River - Calpine | | 11.5 | lbs/hr | | |
| NV-0033 | 8/19/04 | El Dorado Energy, LLC - with duct burner | | 11.6 | lb/hour | LAER | |
| CA-1192 | 6/21/11 | Avenal Power Center LLC | Pipeline Quality Natural Gas | 11.78 | lb/hour | BACT | |
| CA-1191 | 3/11/10 | Victorville 2 Hybrid Power Project | Pipeline Quality Natural Gas | 12.0 | lb/hour | BACT | No duct firing |
| CA | | Metcalf - Calpine | SCR, DLN, Oxidation catalyst | 12 | lbs/hr | w/ duct burner | |
| CA-1191 | | City of Victorville | | 12 | lbs/hr | w/o duct burner | |
| OH-0264 | 5/23/04 | Norton Energy Storage, LLC | | 13 | lb/hour | BACT | |
| CA | | Morro Bay - Duke | | 13.3 | lbs/hr | | |
| CA-1211 | 3/11/11 | Colusa Generating Station | Natural Gas | 13.5 | lb/hour | BACT | |
| CA | | Palomar Energy Project | | 14 | lbs/hr | | |
| OR-0039 | 12/30/03 | California Oregon Border - Peoples Energy | Good Combustion, Natural Gas | 14 | lb/hour | BACT | |
| VA-0315 | 12/17/10 | Virginia Electric and Power Company - Warren County Power Plant - Dominion -with duct burners | Natural Gas with Sulfur Content of 0.0003% by Weight | 14.0 | lb/hour | BACT | |
| VA | 4/30/13 | Stonewall, LLC | Good Combustion Practices and Pipleine Quality Natural Gas | 14.5 | lb/hour | BACT | |

CTG/HRSG BACT Comparison for PM/$PM_{10}$/$PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis | |
|---|---|---|---|---|---|---|---|
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 5 - with duct burner | | 15.0 | lb/hour | BACT | |
| OH-0252 | 12/28/04 | Duke Energy Hanging Rock Energy Facility - turbine only | | 15.0 | lb/hour | BACT | |
| CT-0151 | 2/25/08 | Kleen Energy Systems, LLC - with duct burner | | 15.2 | lb/hour | BACT | |
| VA-0256 | 1/20/02 | Tenaska Fluvanna | Use of Natural Gas | 16.2 | lb/hour | BACT | |
| NC-0095 | 5/28/02 | Mirant Gastonia | Good Combustion Practices | 16.85 | lb/hour | BACT | |
| CA | | La Paloma | | 17.2 | lbs/hr | | |
| TN-0144 | 2/1/02 | Haywood Energy Center (Calpine) | Good Combustion Practices, Clean Fuel | 17.5 | lb/hour | BACT | |
| VA-0289 | 2/5/04 | Duke Energy Wythe, LLC - turbine only | Good Combustion Practices | 17.5 | lb/hour | BACT | |
| CA-1191 | 3/11/10 | Victorville 2 Hybrid Power Project | Pipeline Quality Natural Gas | 18.0 | lb/hour | BACT | with duct firing |
| IN-0086 | 5/9/01 | Mirant Sugar Creek LLC | Good Combustion | 18 | lb/hour | BACT | |
| OH-0268 | 3/26/02 | Lima Energy Company | Use of Clean Burning Fuels | 18 | lb/hour | BACT | |
| OR | | Turner Energy Center | | 18 | lbs/hr | | |
| TX-0234 | 1/8/02 | Edinburg Energy Limited Partnership | | 18 | lb/hour | BACT | |
| TX-0351 | 3/11/02 | Weatherford Electric Generation Facility | None | 18 | lb/hour | Other | |
| TX-0620 | 9/12/12 | ES Joslin Power Plant | | 18.0 | lb/hour | BACT | |
| VA-0262 | 12/6/02 | Mirant Airside Industrial Park | Good Combustion Practices | 18.0 | lb/hour | BACT | |
| WV-0014 | 12/18/01 | Panda Culloden Generating Station | Use of Natural Gas | 18 | lb/hour | BACT | |
| PA-0291 | 4/23/13 | Hickory Run Energy LLC | | 18.5 | lb/hour | Other | |
| MI | 3/16/00 | Southern Energy, Inc. | | 19.0 | lb/hour | BACT | |
| MI-0366 | 4/13/05 | Berrien Energy, LLC | State of the Art Combustion Techniques and Use of Natural Gas | 19.0 | lb/hour | BACT | |
| NM-0044 | 6/27/04 | Clovis Energy Facility - Duke energy Curry LLC | | 19 | lb/hour | BACT | |
| OK-0036 | 12/10/01 | Stephens Energy Facility | | 19.1 | lb/hour | BACT | |
| NJ | 5/31/12 | Woodbridge Energy Center | Use of Natural Gas | 19.1 | lb/hour | BACT | |
| MI-0363 | 1/7/03 | Bluewater Energy Center LLC | Use of Natural Gas | 19.6 | lb/hour | BACT | |
| TX-0590 | 8/5/10 | Pondera Capital Management GP INC - King Power Station | Low Ash Fuel | 19.8 | lb/hour | BACT | |
| CA-1177 | 7/22/09 | Otay Mesa Generating Project | | 20.0 | lb/hour | | |
| FL-0225 | 8/17/01 | El Paso Broward Energy Center | Use of Natural Gas | 20.0 | lb/hour | BACT | |
| FL-0227 | 9/7/01 | El Paso Belle Glade Energy Center | Use of Natural Gas | 20.0 | lb/hour | BACT | |

CTG/HRSG BACT Comparison for $PM/PM_{10}/PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| LA-0164 | 1/31/02 | Acadia Power Station, Acadia Power Partners LLC | Good Design, Good Operating and Maintenance Practices | 20 | lb/hour | BACT |
| TX-0391 | 12/20/02 | Oxy Cogeneration Facility - Oxy Vinyls LP | | 20 | lb/hour | BACT |
| CA | 5/1/2008 | Colussa Generating Station | | 20.1 | lbs/hr | |
| IN-0114 | 7/24/02 | Mirant Sugar Creek LLC | | 20.2 | lb/hour | BACT |
| MS-0055 | 6/24/02 | El Paso Merchant Energy CO. | Use of Low Ash Fuel | 20.5 | lb/hour | BACT |
| MS-0073 | 11/23/04 | Reliant Energy Choctaw County, LLC | | 20.59 | lb/hour | BACT |
| IN-0085 | 6/7/01 | PSEG Lawrenceburg Energy Facility | Good Combustion | 21 | lb/hour | BACT |
| NV-0037 | 5/14/04 | Sempra Energy Resources - Copper Mountain Power | Use of Low-Sulfur Natural Gas | 21.3 | lb/hour | LAER |
| FL-0226 | 9/11/01 | El Paso Manatee Energy Center | Use of Natural Gas | 21.8 | lb/hour | BACT |
| MA-0024 | 4/16/99 | ANP Blackstone | Use of Natural Gas | 21.8 | lb/hour | BACT |
| NC-0094 | 1/9/02 | GenPower Earleys, LLC | Good Combustion Practices and Design | 22 | lb/hour | BACT |
| VA-0255 | 11/18/02 | VA Power - Possum Point | | 22.2 | lb/hour | BACT |
| WA | | Goldendale Energy | | 22.3 | lbs/hr | |
| MA-0025 | 8/4/99 | ANP Bellingham | Use of Natural Gas | 22.6 | lb/hour | BACT |
| LA-0157 | 3/8/02 | Perryville Power Station | Good Operating Practices, Natural Gas | 23 | lb/hour | BACT |
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 4 - turbine only | | 23.0 | lb/hour | BACT |
| OH-0252 | 12/28/04 | Duke Energy Hanging Rock Energy Facility - with duct burner | | 23.3 | lb/hour | BACT |
| VA-0289 | 2/5/04 | Duke Energy Wythe, LLC - with duct burner | Good Combustion Practices | 23.7 | lb/hour | BACT |
| MI-0361 | 1/30/03 | South Shore Power LLC | Use of Natural Gas, State of the Art Combustion Techniques | 24 | lb/hour | BACT |
| MO | 8/19/99 | Kansas City Power & Light Co. - Hawthorn Station | Combustion Controls | 24.0 | lb/hour | BACT |
| LA-0224 | 3/20/08 | Southwest Electric Power Company - Arsenal Hill Power Plant | Good Combustion Design, Proper Operating Practices/Pipeline Quality Natural Gas | 24.23 | lb/hour | BACT |
| VA-0287 | 12/1/03 | James City Energy Park | Good Combustion Design, Clean Fuel | 24.7 | lb/hour | BACT |
| AZ-0043 | 11/12/03 | Duke Energy Arlington Valley | | 25 | lb/hour | BACT |
| GA-0101 | 10/23/02 | Murray Energy Facility | Good Combustion Practices, Clean Fuel | 25 | lb/hour | BACT |

CTG/HRSG BACT Comparison for $PM/PM_{10}/PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| VA-0260 | 5/1/02 | Henry County Power | Good Combustion Design, Clean Fuel | 25.3 | lb/hour | BACT |
| TX-0411 | 3/26/02 | Amelia Energy Center | Natural Gas Combustion | 25.6 | lb/hour | |
| TX-0350 | 1/31/02 | Ennis Tractebel Power | None | 25.62 | lb/hour | BACT |
| MD-0032 | 11/5/04 | Mirant Mid-Atlantic, LLC - Dickerson Unit 4 - with duct burner | | 26.0 | lb/hour | BACT |
| LA-0254 | 8/16/11 | Ninemile Point Electric Generating Plant Units 6A and 6B - without duct burner | Pipeline Natural Gas, Good Combustion Practices | 26.23 | lb/hour | BACT |
| TX-0407 | 12/6/02 | Steag-Stearne | Pipeline Natural Gas | 26.9 | lb/hour | |
| TX-0502 | 6/5/06 | Nacogdoches Power LLC | Pipeline Natural Gas | 26.9 | lb/hour | BACT |
| TX-0618 | 10/15/12 | Channel Energy Center LLC | Good Combustion, Use of Gaseous Fuel | 27.0 | lb/hour | BACT |
| TX-0619 | 9/26/12 | Deer Park Energy Center | Good Combustion, Use of Gaseous Fuel | 27.0 | lb/hour | BACT |
| AZ-0034 | 2/15/01 | Harquahala Generating Project | Combustion Controls | 27.8 | lb/hour | BACT |
| NJ-0043 | 3/28/02 | Liberty Generating Station | | 28.8 | lb/hour | Other |
| AR | 12/29/00 | Duke Energy Hot Springs | Combustion Controls | 29.4 | lb/hour | BACT |
| MN | 11/17/00 | XCEL Energy, Black Dog Electric Generating Station | Use of Natural Gas | 29.4 | lb/hour | BACT |
| NJ-0066 | 2/16/06 | AES Red Oak LLC | Use of Natural Gas | 29.43 | lb/hour | BACT |
| AZ-0047 | 12/1/2004 | Dome Valley Energy Partners, LLC - Wellton Mohawk Generating Station - Scenario 1 | Good Combustion Practices, Natural Gas | 29.8 | lb/hour | BACT |
| AZ | 2003 Dft | La Paz Generating Facility (W501F) | | 30.3 | lb/hour | BACT |
| NC-0086 | 1/10/02 | Fayetteville Generation | Combustion Controls | 31.3 | lb/hour | BACT |
| TX-0388 | 2/12/02 | Sand Hill Energy Center - Austin Electric Utility | | 32 | lb/hour | BACT |
| AR-0051 | 4/1/02 | Duke Energy - Jackson Facility | Good Operating Control, Clean Fuel | 32.2 | lb/hour | BACT |
| MT-0019 | 6/7/02 | Continental Energy Services Inc. - Silver Bow Gen | | 32.4 | lb/hour | Other |
| AZ-0047 | 12/1/2004 | Dome Valley Energy Partners, LLC - Wellton Mohawk Generating Station - Scenario 2 | Good Combustion Practices, Natural Gas | 33.1 | lb/hour | BACT |
| LA-0254 | 8/16/11 | Ninemile Point Electric Generating Plant Units 6A and 6B - with duct burner | Pipeline Natural Gas, Good Combustion Practices | 33.16 | lb/hour | BACT |
| TX-0600 | 9/1/11 | Thomas C. Ferguson Power Plant | Pipeline Quality Natural Gas | 33.43 | lb/hour | BACT |
| LA-0136 | 7/23/08 | Dow Chemical Company - Plaquemine Cogeneration Facility | Use of Clean Burning Fuels | 33.5 | lb/hour | BACT |
| MI-0256 | 1/12/01 | Covert Generating Co LLC | Good Combustion | 33.8 | lb/hour | BACT |
| TX-0381 | 1/31/03 | Ennis Tractebel Power | Pipeline Natural Gas | 37.6 | lb/hour | BACT |

CTG/HRSG BACT Comparison for PM/$PM_{10}$/$PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| TX-0352 | 12/31/02 | Brazos Valley Electric Generating Facility | Good Combustion Control | 38.6 | lb/hour | BACT |
| MS-0059 | 9/24/02 | Pike Generation Facility | Good Combustion Practices, Low Ash Fuel | 44.2 | lb/hour | BACT |
| AZ | 2003 Dft | La Paz Generating Facility (GE 7FA) | | 45.5 | lb/hour | BACT |
| WA-0299 | 4/17/03 | Sumas Energy 2 - NESCO | Good Combustion Practices, Clean Fuel | 0.0039 | lb/mmBtu | BACT - Project Cancelled |
| OR-0040 | 3/12/03 | Klamath Generation LLC - Pacific Power Energy Marketing | Natural Gas | 0.0042 | lb/mmBtu | BACT |
| CA-1212 | 10/18/11 | Palmdale Hybrid Power Project | Use of Pipeline Quality Natural Gas | 0.0048 | lb/mmBtu | BACT - no duct firing |
| CA-1212 | 10/18/11 | Palmdale Hybrid Power Project | Use of Pipeline Quality Natural Gas | 0.0049 | lb/mmBtu | BACT |
| NY-0095 | 5/10/06 | Caithness Bellport, LLC - turbine only | Low Sulfur Fuel | 0.0055 | lb/mmBtu | BACT |
| PA-0286 | 1/13/13 | Moxie Energy LLC/Patriot Energy Plant | | 0.0057 | lb/mmBtu | Other |
| AL-0185 | 7/12/02 | Barton Shoals Energy, LLC | Good Combustion Practices | 0.0060 | lb/mmBtu | BACT |
| NY | 9/27/12 | Cricket Valley Energy Center LLC | Low Sulfur Fuel | 0.0060 | lb/mmBtu | BACT |
| AR-0043 | 2/27/01 | Pine Bluff Energy LLC | Good Combustion Practices | 0.0065 | lb/mmBtu | BACT |
| CO-0052 | 8/11/02 | Rocky Mountain Energy Center | Good Combustion Control Practices, Pipeline Quality Natural Gas | 0.0065 | lb/mmBtu | BACT |
| NY-0095 | 5/10/06 | Caithness Bellport, LLC - with duct burner | Low Sulfur Fuel | 0.0066 | lb/mmBtu | BACT |
| UT-0066 | 5/17/04 | Pacificorp - Currant Creek Power Project | | 0.0066 | lb/mmBtu | BACT |
| OK-0115 | 12/12/06 | Energetix - Lawton Energy Cogen Facility | Good Combustion Practices | 0.0067 | lb/mmBtu | BACT |
| OK-0055 | 2/12/02 | Mustang Energy Project | Use of No-Ash Fuel, Efficient Combustion | 0.007 | lb/mmBtu | BACT |
| CO-0056 | 5/2/06 | Calpine - Rocky Mountain Energy Center, LLC | Natural Gas Quality Fuel Only, Good Combustion Control Practices | 0.0074 | lb/mmBtu | BACT |
| IN-0158 | 12/3/12 | St. Joseph Energy Center LLC | Good Combustion Practice and Fuel Specification | 0.0078 | lb/mmBtu | BACT |
| AL-0141 | 4/10/2000 | GPC-Goat Rock Combined Cycle Plant | Efficient Combustion | 0.009 | lb/mmBtu | BACT |
| AL-0162 | 1/8/2001 | Autaugaville Combined Cycle Plant | Good Combustion | 0.009 | lb/mmBtu | BACT |
| GA-0105 | 4/17/03 | McIntosh Combined Cycle Facility | Good Combustion Practices, Clean Fuel | 0.009 | lb/mmBtu | BACT |
| RI-0019 | 5/3/00 | Reliant Energy Hope Gen. Facility | | 0.009 | lb/mmBtu | BACT |
| VA-0261 | 9/6/02 | CPV Cunningham Creek | Natural Gas | 0.009 | lb/mmBtu | BACT |

CTG/HRSG BACT Comparison for $PM/PM_{10}/PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| OK-0117 | 2/9/07 | Public Service Company of Oklahoma - Southwestern Power Plant | Use of Low Ash Fuel (natural gas), Efficient Combustion | 0.0093 | lb/mmBtu | BACT |
| AL-0167 | 1/26/2001 | Calhoun Power Company I, LLC | Good Combustion Practices | 0.01 | lb/mmBtu | BACT |
| AZ-0039 | 3/7/03 | Salt River Project/Santan Gen. Plant | | 0.01 | lb/mmBtu | LAER |
| LA | | Crescent City Power LLC | | 0.01 | lb/mmBtu | |
| MI-0357 | 2/4/03 | Kalkaska Generating LLC | Good Combustion Practices, Clean Fuel | 0.01 | lb/mmBtu | BACT |
| MN-0053 | 7/15/04 | Fairbault Energy Park | Good Combustion Practices, Clean Fuel | 0.01 | lb/mmBtu | BACT |
| MN-0071 | 6/5/07 | Minnesota Municipal Power Agency - Fairbault Energy Park - turbine only | | 0.01 | lb/mmBtu | BACT |
| MO-0053 | 1/1/96 | Hawthorne Generating Station | | 0.01 | lb/mmBtu | BACT |
| MO-0056 | 3/30/99 | Associated Electric Cooperative, Inc. | Good Combustion | 0.01 | lb/mmBtu | BACT |
| OK-0041 | 1/19/00 | McClain Energy Facility | Clean Fuels | 0.01 | lb/mmBtu | BACT |
| PA-0223 | 1/30/02 | Duke Energy Fayette, LLC | Good Combustion Practices, Use of Natural Gas | 0.01 | lb/mmBtu | BACT |
| OH-0248 | 9/24/02 | Lawrence Energy - Calpine Corporation | Burning Natural Gas | 0.0101 | lb/mmBtu | BACT |
| GA | 5/30/12 | Effingham County Power Plant | Pipeline Quality Natural Gas | 0.0103 | lb/mmBtu | BACT |
| IA-0058 | 4/10/02 | MidAmerican Energy, Des Moines Power Station | | 0.0108 | lb/mmBtu | BACT |
| GA-0102 | 1/15/02 | Wansley Combined Cycle Energy Facility | Good Combustion Practices, Low Sulfur Fuel | 0.011 | lb/mmBtu | BACT |
| MS-0040 | 12/31/98 | Mississippi Power Plant | | 0.011 | lb/mmBtu | BACT |
| NV-0035 | 8/16/05 | Sierra Pacific Power Company - Tracy Substation Expansion Project | Best Combustion Practices | 0.011 | lb/mmBtu | BACT |
| OK-0056 | 2/12/02 | Horseshoe Energy Project | Low Ash Fuel | 0.0117 | lb/mmBtu | BACT |
| AL-0143 | 3/3/2000 | AEC-McWilliams Plant | Good Combustion | 0.012 | lb/mmBtu | BACT |
| IN-0087 | 6/6/01 | Duke Energy, Vigo LLC | Good Combustion | 0.012 | lb/mmBtu | BACT |
| OK-0096 | 6/6/03 | Redbud Power Plant | Efficient Combustion, Low Ash Fuel | 0.012 | lb/mmBtu | BACT |
| AL-0169 | 2/5/2001 | Blount Megawatt Facility | Good Combustion Practices | 0.013 | lb/mmBtu | BACT |
| AR-0035 | 8/24/00 | Panda - Union Generating Station | Clean Fuels, Proper Operation | 0.014 | lb/mmBtu | BACT |
| AZ-0038 | 4/30/02 | Gila Bend Power Generation Station | | 0.014 | lb/mmBtu | BACT |
| PA-0188 | 3/28/02 | Fairless Energy LLC | | 0.014 | lb/mmBtu | BACT |
| PA-0226 | 4/9/02 | Limerick Partners, LLC | | 0.014 | lb/mmBtu | BACT |
| OK-0043 | 10/22/01 | Webers Falls Energy Facility | Efficient Combustion | 0.015 | lb/mmBtu | BACT |

CTG/HRSG BACT Comparison for $PM/PM_{10}/PM_{2.5}$

| RBLC ID | Permit Date | Facility | Control Technology | Emiss. Limit | Emiss. Limit Unit | Basis |
|---|---|---|---|---|---|---|
| OK-0090 | 3/21/03 | Duke Energy Stephens, LLC | Clean Fuel, Efficient Combustion | 0.015 | lb/mmBtu | BACT |
| MO-0058 | 5/9/00 | Audrain Generating Station | Good Combustion | 0.016 | lb/mmBtu | BACT |
| NC-0101 | 9/29/05 | Forsyth Energy Projects, LLC - turbine only | Good Combustion Practices, Clean Burning Low Sulfur Fuel | 0.019 | lb/mmBtu | BACT |
| OK-0070 | 6/13/02 | Genova OK I Power Project | Low Sulfur Fuel, Efficient Combustion | 0.019 | lb/mmBtu | BACT |
| AL-0132 | 11/29/1999 | Tenaska Alabama Generating Station | Efficient Combustion | 0.02 | lb/mmBtu | BACT |
| AR-0070 | 8/23/02 | Genova Arkansas I, LLC | Good Combustion Practices | 0.02 | lb/mmBtu | BACT |
| DE-0016 | 10/17/00 | Hay Road Power Complex Units 5-8 | Clean Fuels | 0.02 | lb/mmBtu | BACT |
| NC-0101 | 9/29/05 | Forsyth Energy Projects, LLC - with duct burner | Good Combustion Practices, Clean Burning Low Sulfur Fuel | 0.021 | lb/mmBtu | BACT |
| PA-0189 | 1/16/02 | Connectiv - Bethlehem North | | 0.0135 | ppm | BACT |
| MI-0365 | 1/28/03 | Mirant Wyandotte LLC | Good Combustion Practices, Use of Pipeline Quality Natural Gas | 5.6 | mg/cm | BACT |
| WA-0291 | 1/3/03 | Wallula Power - Newport Northwest Generation | Natural Gas | 0.0029 | gr/dscf | LAER |
| OR-0035 | 1/16/02 | Port Westward - Portland General Electric | Use of Pipeline Quality Natural Gas | 0.1 | gr/dscf | BACT |
| OR-0048 | 12/29/10 | Portland General Electric Carty Plant | Clean Fuel | 2.5 | lb/MMCF | BACT |
| DE-0024 | 1/30/2013 | Garrison Energy Center, LLC/Calpine Corporation | Fuel usage restriction to natural gas and low sulfur distillate fuel | 120.4 | tons/year | BACT |

Table contains: Entries from the EPA turbine spreadsheet with a permit issuance date after 2002
Entries from the RBLC for new units with a permit issuance date 2002 - 2013
Information from state agency websites

**BOWIE POWER STATION**
**AUXILIARY BOILER $NO_x$ CONTROL**
**COST EFFECTIVENESS**

| | |
|---|---|
| Boiler Size (mmBtu/hour) | 50 |

| | |
|---|---|
| Interest Rate | 7 |
| Equipment Life (years) | 15 |
| Capital Recovery Factor | 0.11 |

| **Emission Reduction** | **tons/year**[a] | **ppmv**[b] |
|---|---|---|
| Auxiliary Boiler $NO_x$ Emissions | 0.41 | 30 |

| | |
|---|---|
| SNCR Capital Cost ($/mmBtu/hour)[c] | $4,297 |
| SNCR Capital Cost ($) | $214,850 |
| SCR Capital Cost ($/mmBtu/hour)[c] | $8,359 |
| SCR Capital Cost ($) | $417,950 |

| | **Control Efficiency**[d] | **Emission Concentration (ppmv)** | **Controlled Emissions (tons/year)** | **Reduction (tons/year)** | **Annualized Cost**[f] **($/year)** | **Cost Effectiveness ($/ton)** |
|---|---|---|---|---|---|---|
| SNCR | 75% | | 0.10 | 0.31 | $23,589 | $76,713 |
| SCR | 90% | | 0.04 | 0.37 | $45,889 | $124,360 |
| Ultra Low NOx Burners[e] | | 9 | 0.12 | 0.29 | $33,560 | $116,934 |

[a]From spreadsheet "Bowie Power Station Auxiliary Boiler Data and Emissions"

[b]From manufacturer's data sheet.

[c]From "Applicability and Feasibility of $NO_x$, $SO_2$ and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers", Northeast States for Coordinated Air Use Management in Parnership with the Mid-Atlantic/Northeast Visibility Union, November 2008, pages 2-16 and 2-18.

[d]From "NOx Controls Technologies", Institute of Clean Air Companies (ICAC), http://www.icac.com/?Nox_Controls

[e]Emission concentration is from "Final Draft Staff Report for Rules 4306, 4307, and 4320", San Joaquin Valley Unified Air Pollution Control District, September 18, 2008, page 2.

[f]Ultra Low $NO_x$ burner values are from "Final Draft Staff Report for Rules 4306, 4307, and 4320", San Joaquin Valley Unified Air Pollution Control District, September 18, 2008, Table C-8, page C-10 for a 44 mmBtu/hour boiler with a 50% capacity factor.

Capital Recover Factor calculated in accordance with "EPA Air Pollution Control Cost Manual", equation 2.8a (page 2-21):

$$\text{Capital Recover Factor} = \frac{(\text{interest rate} \times (1 + \text{interest rate})^{\text{equipment life}})}{((1 + \text{interest rate})^{\text{equipment life}} - 1)}$$

$$\text{SNCR and SCR Capital Cost } \$ = \text{Capital Cost } \frac{\$}{\text{mmBtu/hour}} \times \text{ Boiler Size mmBtu/hour}$$

$$\text{Controlled Emissions } \frac{\text{tons}}{\text{year}} = \text{Boiler Emissions } \frac{\text{tons}}{\text{year}} \times (1 - \text{Control Efficiency})$$

$$\text{Ultra Low } NO_x \text{ Burner Emission } \frac{\text{tons}}{\text{year}} = \frac{\text{Ultra Low } NO_x \text{ Burner Emission Concentration ppmv}}{\text{Auxiliary Boiler } NO_x \text{ Emission Concentration ppmv}} \times \text{Low } NO_x \text{ Burner Emissions } \frac{\text{tons}}{\text{year}}$$

$$\text{Emission Reduction } \frac{\text{tons}}{\text{year}} = \text{Boiler Emissions } \frac{\text{tons}}{\text{year}} - \text{Controlled Emissions } \frac{\text{tons}}{\text{year}}$$

$$\text{Annualized SNCR and SCR Cost } \frac{\$}{\text{year}} = \text{Capital Cost } \$ \times \text{Capital Recovery Factor}$$

$$\text{Cost Effectiveness } \frac{\$}{\text{year}} = \frac{\text{Total Annual Cost (\$/year)}}{\text{Emission Reduction (tons/year)}}$$

EPA/452/B-02-001

# EPA AIR POLLUTION CONTROL COST MANUAL

Sixth Edition

EPA/452/B-02-001

January 2002

United States Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Annualization is a process similar to EUAC but is not limited to constant cash flows. It involves determining the net present value of each alternative equipment investment and then determining the equal (in nominal terms) payment that would have to be made at the end of each year to attain the same level of expenditure. In essence, annualization involves establishing an annual "payment" sufficient to finance the investment for its entire life, using the formula:

$$PMT = NPV\left(\frac{i}{1-(1+i)^{-n}}\right) \qquad (2.7)$$

where *PMT* is the equivalent uniform payment amount over the life of the control, *n*, at an interest rate, *i*. *NPV* indicates the present value of the investment as defined above in equation 2.6.

Engineering texts call this payment the capital recovery cost (*CRC*), which they calculate by multiplying the *NPV* of the investment by the capital recovery factor (*CRF*):

$$CRC = NPV \times CRF \qquad (2.8)$$

where *CRF* is defined according to the formula:

$$\mathrm{CRF} = \left(\frac{\mathrm{i}(1+\mathrm{i})^{\mathrm{n}}}{(1+\mathrm{i})^{\mathrm{n}}-1}\right) \qquad (2.8a)$$

The *CRF* equation is a transformation of the *PMT* form in equation 2.7 and returns the same information. Table A.2 in Appendix A lists the *CRF* for discount rates between 5.5 percent and 15 percent for annualization periods from one to 25 years.

2.4.4.5 Other Financial Analysis Tools

Many firms make investment decisions based upon the return on investment (*ROI*) of the proposed capital purchase, rather than the magnitude of its net present value. In and of itself, the ROI of an investment opportunity is of little use. For most pollution control investments, *ROI* analysis does not provide much in the way of useful information because, like a payback analysis, it must have positive cash flows to work properly. Calculated by dividing annual net income by the investment's capital cost, results in a percentage of the investment that is returned each year. The decision rule one should apply for *ROI* analysis is if the resulting percentage is at least as large as some established minimum rate of return, then the investment would be worth while. However, different industries require different rates of return on investments, and even within an industry, many different rates can be found. Analysts should consult with their firm's financial officers or an industrial association to determine what percentage would apply.

# Applicability and Feasibility of NOx, $SO_2$, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers

**Northeast States for Coordinated Air Use Management (NESCAUM)**

**November 2008**

(revised January 2009)

**Table 2-5. NOx control costs for SNCR applied to ICI boilers**

| Technology | NOx Reduction Range | Fuel Type | Size of Boiler (MMBtu/hr) | Capital Costs @2006$ ($/MMBtu/hr) | Base yr. for or Ref. yr | Cost ($/ton NOx @ base year) | Ref. |
|---|---|---|---|---|---|---|---|
| SNCR | 30%-70% | Coal | 500 | $2,044 | 1996 | | 1 |
| SNCR | 40% | Coal | 100 | $6,717 | 1999 | | 6 |
| SNCR | 40% | Coal | 250 | $5,102 | 1999 | | 6 |
| SNCR | 40% | Coal | 1000 | $3,366 | 1999 | | 6 |
| SNCR | 30%-70% | Resid. Oil | 50 | $4,297 | 1996 | | 1 |
| SNCR | 30%-70% | Resid. Oil | 150 | $4,297 | 1996 | | 1 |
| SNCR | 35% | | 350 | $2,862 | 1999 | | 2 |
| SNCR | | | 21 | $17,101 | 2006 | $3,718 | 4 |
| SNCR | | | 120 | $6,377 | 2006 | $2,231 | 4 |
| SNCR | | | 240 | $4,493 | 2006 | $1,821 | 4 |
| SNCR | | | 387 | $2,899 | 2006 | $1,564 | 4 |
| SNCR | | | 543 | $2,319 | 2006 | $1,538 | 4 |
| SNCR | | | 844 | $1,449 | 2006 | $1,346 | 4 |
| SNCR | 40% | Oil | 100 | $5,205 | 1999 | | 6 |
| SNCR | 40% | Oil | 250 | $3,954 | 1999 | | 6 |
| SNCR | 40% | Oil | 1000 | $2,608 | 1999 | | 6 |
| SNCR | 30%-70% | Dist. Oil | 50 | $4,297 | 1996 | | 1 |
| SNCR | 30%-60% | Natural Gas | 50 | $4,297 | 1996 | | 1 |
| SNCR | 40% | Gas | 100 | $5,372 | 1999 | | 6 |
| SNCR | 40% | Gas | 250 | $4,082 | 1999 | | 6 |
| SNCR | 40% | Gas | 1000 | $2,693 | 1999 | | 6 |
| LNB+SNCR | 50%-89% | Pulv. Coal | 250 | $2,064-6,829 | 2005 | $1,409-$4,473 | 3 |
| LNB+SNCR | 50%-89% | Resid. Oil | 250 | $2,064-6,829 | 2005 | $2,229-$7,909 | 3 |

References:


1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.

ductwork required, significant variation in installed capital cost can occur for a given boiler size. Upgrades like rebuilding the air preheater also affect the installed capital cost. MACTEC [2005] gave the cost effectiveness (in dollars per ton of NOx removed) for SCR for coal and residual oil; these costs showed a wide range, because of the wide range in assumed capital costs.

**Table 2-6. NOx control costs for SCR applied to ICI boilers**

| Technology | NOx Reduction Range | Fuel Type | Size of Boiler (MMBtu/hr) | Capital Costs @2006$ ($/MMBtu/hr) | Base yr. for or Ref. yr | Cost ($/ton NOx @ base year) | Ref. |
|---|---|---|---|---|---|---|---|
| SCR | 80% | Coal | *350* | $12,755-19,133 | 1999 | | 2 |
| SCR | 80%-90% | Coal | 500 | $15,365-16,145 | 1996 | | 1 |
| SCR | 70%-90% | Pulv. Coal | 250 | $1,666-13,881 | 2005 | $2,233-$7,280 | 3 |
| SCR | 80% | Coal | 100 | $18,574 | 1999 | | 6 |
| SCR | 80% | Coal | 250 | $14,110 | 1999 | | 6 |
| SCR | 80% | Coal | 1000 | $9,309 | 1999 | | 6 |
| SCR | 80% | Oil | 100 | $14,116 | 1999 | | 6 |
| SCR | 80% | Oil | 250 | $10,723 | 1999 | | 6 |
| SCR | 80% | Oil | 1000 | $7,075 | 1999 | | 6 |
| SCR | -- | Oil | -- | $5,102-7,653 | 1999 | | 5 |
| SCR | 70%-90% | Resid. Oil | 250 | $1,666-13,881 | 2005 | $4,363-$14,431 | 3 |
| SCR | 80%-90% | Resid. Oil | 50 | $8,359 | 1996 | | 1 |
| SCR | 80%-90% | Resid. Oil | 150 | $4,909 | 1996 | | 1 |
| SCR | 80%-90% | Dist. | 50 | $8,359 | 1996 | | 1 |
| SCR | 80%-90% | Dist. | 150 | $4,909 | 1996 | | 1 |
| SCR | 80% | Gas | 100 | $10,216 | 1999 | | 6 |
| SCR | 80% | Gas | 250 | $7,760 | 1999 | | 6 |
| SCR | 80% | Gas | 1000 | $5,120 | 1999 | | 6 |
| SCR | 80% | Gas | 100 | $9,566 | 1999 | | 2 |
| SCR | 80% | Gas | 350 | $7,015 | 1999 | | 2 |
| SCR | 80%-90% | Natural Gas | 50 | $8,359 | 1996 | | 1 |
| SCR | 80%-90% | Natural Gas | 150 | $4,909 | 1996 | | 1 |
| SCR | 80% | Wood | 350 | $6,378-7,653 | 1999 | | 2 |
| SCR | 74% | Wood | 321 | $1,978 | 2006 | $4,514 | 7 |

References:

1. US EPA, OTAG Technical Supporting Document, Chapter 5, Appendix C, 1996. http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/
2. NESCAUM, *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and I.C. Engines - Technologies & Cost Effectiveness*, (Praveen Amar, Project Director), December 2000.
3. MACTEC, *Boiler Best Available Retrofit Technology (BART) Engineering Analysis*; Lake Michigan Air Directors Consortium (LADCO): March 30, 2005.
4. Whiteman, C., ICAC, "Selective Non-Catalytic Reduction Technology Costs for Industrial Sources," memo to Christopher Recchia, Executive Director, Ozone Transport Commission, October 6, 2006.
5. US EPA Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR); EPA-452/F-03-032, July 15, 2003. http://www.epa.gov/ttn/catc/dir1/fscr.pdf
6. Khan, S. Methodology, Assumptions, and References Preliminary NOx Controls Cost Estimates for Industrial Boilers; US EPA: 2003.
7. BPEI. (2008, February). RSCR Cost Effective Analysis.

# Nox Controls



## Selective Catalytic Reduction (SCR)

SCR is a process for controlling emissions of nitrogen oxides from stationary sources. The basic principle of SCR is the reduction of NOx to N2 and H2O by the reaction of NOx and ammonia (NH3) within a catalyst bed. The primary reactions occurring in SCR require oxygen, so that catalyst performance is best at oxygen levels above 2-3%.
Several different catalysts are available for use at different exhaust gas temperatures. In use the longest and most common are base metal catalysts, which typically contain titanium and vanadium oxides, and which also may contain molybdenum, tungsten, and other elements. Base metal catalysts are useful between 450 °F and 800 °F. For high temperature operation (675 °F to over 1100 °F), zeolite catalysts may be used. In clean, low temperature (350-550 °F) applications, catalysts containing precious metals such as platinum and palladium are useful. (Note that these compositions refer to the catalytically active phase only; additional ingredients may be present to give thermal and structural stability, to increase surface area, or for other purposes.)

The mechanical operation of an SCR system is quite simple. It consists of a reactor chamber with a catalyst bed, composed of catalyst modules, and an ammonia handling and injection system, with the ammonia injected into the flue gas upstream of the catalyst. (In some cases, a fluidized bed of catalyst pellets is used.) There are no moving parts. Other than spent catalyst, the SCR process produces no waste products.

In principle, SCR can provide reductions in NOx emissions approaching 100%. (Simple thermodynamic calculations indicate that a reduction of well over 99% is possible at 650 °F.) In practice, commercial SCR systems have met control targets of over 90% in many cases.

## Selective Non-Catalytic Reduction (SNCR)

SNCR is a chemical process that changes oxides of nitrogen (NOx) into molecular nitrogen (N2). A reducing agent, typically ammonia or urea, is injected into the combustion/process gases. At suitably high temperatures (1,600 - 2,100 °F), the desired chemical reactions occur. Other chemicals can also be added to improve performance, reduce equipment maintenance, and expand the temperature window within which SNCR is effective.
Conceptually, the SNCR process is quite simple. A gaseous or aqueous reagent of a selected nitrogenous compound is injected into, and mixed with, the hot flue gas in the proper temperature range. The reagent then, without a catalyst, reacts with the NOx in the gas stream, converting it to harmless nitrogen gas and water vapor. SNCR is "selective" in that the reagent reacts primarily with NOx, and not with oxygen or other major components of the flue gas.

No solid or liquid wastes are created in the SNCR process.

In almost all commercial SNCR systems, either ammonia or urea is used as the reagent. Other reagents such as cyanuric acid and hydrazine have also been used. Ammonia may be injected in either anhydrous or aqueous form, and urea, as an aqueous solution.

The principal components of an SNCR system are a reagent storage and injection system, which includes tanks, pumps, injectors, and associated controls, and often NOx continuous emissions monitors. Given the simplicity of these components, installation of SNCR is easy relative to the installation of other NOx control technologies. SNCR retrofits typically do not require extended source shutdowns.

While SNCR performance is specific to each unique application, NOx reduction levels ranging from 30% to over 75% have been reported.

Temperature, residence time, reagent injection rate, reagent-flue gas mixing, and uncontrolled NOx level are important in determining the effectiveness of SNCR. In general, if NOx and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NOx level.

SNCR will remove the most NOx within a specified temperature range or window. At temperatures below the window, reaction rates are extremely low, so that little or no NOx reduction occurs. On the left side of the curve, the extent of NOx removal increases with increasing temperature because reaction rates increase with temperature. Residence time typically limits the NOx reduction in this range. At the plateau, reaction rates are optimal for NOx reduction. A temperature variation in this range will have only a small effect on NOx reduction.

A further increase in temperature beyond the plateau decreases NOx reduction. On the right side of the curve, the oxidation of reagent becomes a significant path and competes with the NOx reduction reactions for the reagent. A further increase in temperature beyond the right side can actually increase the level of NOx. Although the reduction is less than the optimum, operation on the right side is practiced and recommended to minimize reaction times and byproduct emissions.

The temperature window becomes wider as the residence time increases, thus improving the removal characteristics of the process. Long residence times (>0.5 second) at optimum temperatures promote relatively high NOx reduction performance even with less than optimum mixing or temperatures.

Normal stoichiometric ratio (NSR) is the term used to describe the N/NO molar ratio of the reagent injected to uncontrolled NOx concentrations. If one mole of anhydrous ammonia is injected for each mole of NOx in the flue gas, the NSR is one, as one mole of ammonia will react with one mole of NOx. If one mole of urea is injected into the flue gas for each mole of NOx, the NSR is two. This is because one mole of urea will react with two moles of NOx. For both reagents, the higher the NSR, the greater the level of NOx reduction. Increasing NSR beyond a certain point, however, will have a diminishing effect on NOx reduction, with reagent utilization decreasing beyond this point.

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## SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

## FINAL DRAFT STAFF REPORT

September 18, 2008

**Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3)**
**Proposed Amendments to Rule 4307 (Boilers, Steam Generators, and Process Heaters – 2.0 MMBtu/hr to 5.0 MMBtu/hr)**
**Proposed New Rule 4320 (Advanced Emission Reduction Options For Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr)**

Prepared by: Manuel Salinas, Air Quality Engineer

Reviewed by: Errol Villegas, Planning Manager
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Joven R. Nazareno, Senior Air Quality Engineer
Rich Karrs, Senior Air Quality Engineer
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## I. SUMMARY

### A. Reasons for Rule Development and Implementation

The San Joaquin Valley Air Basin (SJVAB) is a continuous inter-mountain valley comprised of eight counties in the southern portion of the San Joaquin Valley of California: Fresno, Kings, Madera, Merced, San Joaquin, Stanislaus, Tulare, and the Valley portion of Kern. The SJVAB is approximately 250 miles long, averages 80 miles wide, and is partially enclosed by the Coast Mountain range on the west, the Tehachapi Mountains on the south, and the Sierra Nevada range on the east. These surrounding mountains trap pollution. Low wind speeds combined with low-lying inversion layers in the winter create a climate conducive to the formation of high particulate matter (PM) concentrations. The region's hot, dry summers are conducive to ozone formation.

The SJVAB is currently designated as nonattainment for the national ambient air quality standard (NAAQS) for particulate matter 2.5 microns in diameter or less (PM2.5) and serious nonattainment for the eight-hour ozone NAAQS. Prior to the United States Environmental Protection Agency's (EPA's) implementation of the eight-hour ozone standard, the SJVAB was also classified as an extreme nonattainment area for the one-hour ozone NAAQS. Although EPA revoked the one-hour ozone NAAQS, the San

Table C-7 reflects the costs for installing ULNB on refinery units, which have a 30 ppmv NOx limit under Rule 4306, and achieving a 9 ppmv level for initial Rule 4320 compliance. These units typically operate at a 75% capacity factor and the average cost effective level of $8,600/ton is considered representative for the typical unit, although the $10,000 to $12,000/ton values for the smaller units is also considered to be very cost effective. Table C-8 has costs for lower-use refinery units.

Table C-7 ULNB Cost Effectiveness Calculation for Units at 75% Capacity Factor

30 ppmv to 9 ppmv Cost Effectiveness

| Actual Size MMBtu/hr | Capital Cost $ | Installation Cost $ | Annualized Capital Cost | Incremental Elec. $/yr | Incremental O&M $/yr | Annualized Cost $/yr | NOx reduced tons/yr | CE $/ton NOx |
|---|---|---|---|---|---|---|---|---|
| 150 | $214,411 | $40,000 | $41,469 | $34,995 | $4,950 | $81,414 | 12.32 | $6,609 |
| 130 | $194,560 | $40,000 | $38,233 | $30,329 | $4,275 | $72,837 | 10.68 | $6,823 |
| 115 | $179,672 | $40,000 | $35,807 | $26,829 | $3,825 | $66,461 | 9.44 | $7,037 |
| 92 | $151,766 | $30,000 | $29,628 | $21,463 | $3,075 | $54,166 | 7.56 | $7,170 |
| 68 | $127,200 | $30,000 | $25,624 | $15,864 | $2,250 | $43,738 | 5.58 | $7,833 |
| 44 | $114,172 | $20,000 | $21,870 | $10,265 | $1,425 | $33,560 | 3.613 | $9,289 |
| 33.8 | $94,762 | $20,000 | $18,706 | $7,885 | $1,125 | $27,716 | 2.78 | $9,988 |
| 14.7 | $37,750 | $15,000 | $8,598 | $3,429 | $450 | $12,477 | 1.21 | $10,337 |
| 8.4 | $28,550 | $10,000 | $6,284 | $1,960 | $300 | $8,544 | 0.69 | $12,400 |
| | | | | | | Average Cost Effectiveness | | $8 609.56 |

Table C-8 – ULNB Cost Effectiveness Calculation for Units at 50% Capacity Factor

30 ppmv to 9 ppmv Cost Effectiveness

| Actual Size MMBtu/hr | Capital Cost $ | Installation Cost $ | Annualized Capital Cost | Incremental Elec. $/yr | Incremental O&M $/yr | Annualized Cost $/yr | NOx reduced tons/yr | CE $/ton NOx |
|---|---|---|---|---|---|---|---|---|
| 150 | $214,411 | $40,000 | $41,469 | $34,995 | $4,950 | $81,414 | 8.212 | $9,914 |
| 130 | $194,560 | $40,000 | $38,233 | $30,329 | $4,275 | $72,837 | 7.117 | $10,234 |
| 115 | $179,672 | $40,000 | $35,807 | $26,829 | $3,825 | $66,461 | 6.296 | $10,556 |
| 92 | $151,766 | $30,000 | $29,628 | $21,463 | $3,075 | $54,166 | 5.037 | $10,754 |
| 68 | $127,200 | $30,000 | $25,624 | $15,864 | $2,250 | $43,738 | 3.723 | $11,748 |
| 44 | $114,172 | $20,000 | $21,870 | $10,265 | $1,425 | $33,560 | 2.409 | $13,931 |
| 33.8 | $94,762 | $20,000 | $18,706 | $7,885 | $1'125 | $27,716 | 1.85 | $14,982 |
| 14.7 | $37,750 | $15,000 | $8,598 | $3,429 | $450 | $12,477 | 0.804 | $15,519 |
| 8.4 | $28,550 | $10,000 | $6,284 | $1,960 | $300 | $8,544 | 0.459 | $18,614 |
| | | | | | | Average Cost Effectiveness | | $12,916.89 |

**BOWIE POWER STATION**
**EMERGENCY FIRE PUMP ENGINE**
**POST COMBUSTION CONTROL OPTIONS**
**COST EFFECTIVENESS**

| | |
|---|---|
| Interest Rate | 7 |
| Equipment Life (years) | 15 |
| Capital Recovery Factor | 0.11 |

| | |
|---|---|
| Fire Pump Size (hp) | 260 |

**$NO_x$**

| | |
|---|---|
| Fire Pump Engine $NO_x$ Emissions (tons/year)[a] | 0.063 |
| NOxTech Capital Cost ($/hp)[b] | 50 |
| NOxTech Cost ($) | $13,000 |

| Control Option | Control Efficiency[c] | Emissions with Control (tons/year) | Reduction (tons/year) | Capital Cost ($) | Total Annual Cost ($/year)[d] | Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|
| SCR | 95% | 0.00315 | 0.060 | | $ 9,520 | $ 159,064 |
| NOxTech | 95% | 0.00315 | 0.060 | $ 13,000 | $ 1,427 | $ 23,848 |

**CO**

| | |
|---|---|
| Fire Pump Engine CO Emissions (tons/year)[a] | 0.041 |

| Control Option | Control Efficiency[e] | Emissions with Control (tons/year) | Reduction (tons/year) | Total Annual Cost ($/year)[f] | Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Oxidation Catalyst | 90% | 0.0041 | 0.037 | $ 1,777 | $ 48,168 |
| Catalyzed Diesel Particulate Filter | 90% | 0.0041 | 0.037 | $ 4,430 | $ 120,054 |
| Flow through Filters | 90% | 0.0041 | 0.037 | $ 1,523 | $ 41,285 |

**$PM/PM_{10}/PM_{2.5}$**

| | |
|---|---|
| Fire Pump Engine $PM/PM_{10}/PM_{2.5}$ Emissions (tons/year)[a] | 0.0034 |

| | |
|---|---|
| Diesel Particulate Filter Capital Cost ($/hp)[g] | $38 |
| Diesel Particulate Filter Capital Cost ($) | $9,880 |

| Control Option | Control Efficiency[h] | Emissions with Control (tons/year) | Reduction (tons/year) | Total Annual Cost ($/year)[i] | Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|
| Diesel Particulate Filter | 90% | 0.00034 | 0.0031 | $ 1,085 | $ 354,500 |
| Catalyzed Diesel Particulate Filter | 90% | 0.00034 | 0.0031 | $ 4,430 | $ 1,447,712 |
| Flow through Filters | 75% | 0.00085 | 0.0026 | $ 1,523 | $ 597,412 |

[a]From spreadsheet "Bowie Power Station Emergency Fire Pump Data and Emissions"

[b]From memorandum "NOx Control Technologies for Stationary Diesel ICE", from Tanya Parise, Alpha-Gamma Technologies, Inc., to Sims Roy, EPA OAQPS ESD Combustion Group, dated June 20, 2005, page 6.

[c]Control efficiencies are assumed

[d]SCR annual cost is from "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, page 58, entry for engines 175 - 300 hp.

[e]From "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, pages 34, 41, and 43.

[f]Cost equations are from "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, pages 59, 64, and 68.

[g]From presentation "Public Hearing to Consider the Adoption of the Airborne Toxic Control Measure to Reduce Diesel Particulate Matter Emissions from Stationary Engines", by the California Environmental Protection Agency, Air Resources Board, February 26, 2004, slide 5.

[h]From "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, pages 34 and 43.

[i]For catalyzed diesel particulate filter and flow through filters equations are from "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, pages 59 and 68.

Capital Recover Factor calculated in accordance with "EPA Air Pollution Control Cost Manual", equation 2.8a (page 2-21):

$$\text{Capital Recover Factor} = \frac{(\text{interest rate} \times (1 + \text{interest rate})^{\text{equipment life}})}{((1 + \text{interest rate})^{\text{equipment life}} - 1)}$$

$$\text{NOxTech Capital Cost } \$ = \text{Capital Cost } \frac{\$}{\text{hp}} \times \text{ Fire Pump Size hp}$$

$$\text{Controlled Emissions } \frac{\text{tons}}{\text{year}} = \text{Fire Pump Emissions } \frac{\text{tons}}{\text{year}} \times (1 - \text{Control Efficiency})$$

$$\text{Emission Reduction } \frac{\text{tons}}{\text{year}} = \text{Boiler Emissions } \frac{\text{tons}}{\text{year}} - \text{Controlled Emissions } \frac{\text{tons}}{\text{year}}$$

$$\text{Annualized Cost } \frac{\$}{\text{year}} = \text{Capital Cost } \$ \times \text{Capital Recovery Factor}$$

$$\text{Cost Effectiveness } \frac{\$}{\text{year}} = \frac{\text{Total Annual Cost } (\$/\text{year})}{\text{Emission Reduction (tons/year)}}$$

Oxidation Catalyst Annual Cost Equation from "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, pages 64:

$$\text{Total Annualized Cost } \frac{\$}{\text{year}} = (4.99 \times \text{engine size in hp}) + 480$$

Catalyzed Diesel Particulate Filter Annual Cost Equation from "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, pages 59:

$$\text{Total Annualized Cost } \frac{\$}{\text{year}} = (11.6 \times \text{engine size in hp}) + 1{,}414$$

$$\text{Diesel Particulate Filter Capital Cost } \$ = \frac{\$}{\text{hp}} \times \text{hp}$$

Flow Through Filter Annual Cost Equation from "Alternative Control Techniques Document: Stationary Diesel Engines", U.S. EPA, March 5, 2010, pages 68:

$$\text{Total Annualized Cost } \frac{\$}{\text{year}} = (2.89 \times \text{engine size in hp}) + 772$$

MEMORANDUM

DATE: June 20, 2005

SUBJECT: $NO_X$ Control Technologies for Stationary Diesel ICE

FROM: Tanya Parise, Alpha-Gamma Technologies, Inc.

TO: Sims Roy, EPA OAQPS ESD Combustion Group

---

The purpose of this memorandum is to present information on different types of nitrogen oxides (NOx) controls that can be applied to stationary internal combustion engines (ICE) operating on diesel fuel.

## Introduction

Several control technologies capable of reducing NOx emissions from stationary ICE are discussed within this memorandum. Add-on or post-combustion controls (also referred to as secondary methods of control) for NOx are control methods designed to treat the exhaust emissions from stationary ICE once NOx emissions have formed. On-engine or in-cylinder controls (also referred to as primary methods of control) for NOx are control methods designed to minimize the amount of NOx formed. Control methods that are commercially available and control technologies that are under development are discussed. Table 1 presents a summary of the NOx emissions reductions that can be achieved for the control methods discussed in this paper.

## Commercially Available

### Add-On Control

Selective Catalytic Reduction

Selective catalytic reduction (SCR) has been on the market and proven reliable for over 15 years. However, it has not been widely used for engines. Miratech, Johnson Matthey, Engelhard, RJM, Wartsila and Catalyst Products are some manufacturers that make SCR. Selective catalytic reduction is often used in combination with an oxidation catalyst and is the only commercially proven secondary NOx reduction method for lean burn gas and diesel engines. The following requirements and difficulties are associated with applying SCR:

Costs

According to literature available from NOxTech Inc. website, NOxTech® system capital costs are about $50-150/bhp-hr for diesel engines. The company also states on their website that NOxTech® treatment costs are not expected to exceed about $1,000/ton of $NO_2$ equivalent NOx reduction. The company claims that the NOxTech® system can provide the end use a 50 percent cost reduction in comparison with SCR systems.

Experience

According to EC/R's report, the NOxTech® system is operating on several diesel generators owned by Southern California Edison. At its Catalina Island facility, NOxTech® is used on 2.5 MW (3,350 hp) and 3.8 MW (5,092 hp) diesel electric generators. At its Pebbly Beach generating station, NOxTech® is used on 1.5 MW (2,010 hp) and 2.8 MW (3,752 hp) diesel generators.

On-Engine Control Methods

Ceramic Coating

Ceramic engine coatings have been used for several years in stationary and mobile diesel engines to reduce PM emissions. Ceramic engine coatings improve combustion by reflecting heat away from coated components back into the combustion gas path.

Emissions Reductions

According to the Manufacturers of Emission Controls Association (MECA), testing indicated that ceramic engine coating combined with an oxidation catalyst may reduce NOx emissions from a diesel engine, by allowing the engine timing to be retarded, by 40 percent. According to MECA, reductions of 60 and 80 percent for non-methane hydrocarbons (NMHC) and CO, respectively, are possible with an oxidation catalyst and engine coatings. One manufacturer of ceramic coatings for diesel engines stated that significant HC and CO reductions can be achieved, however, an estimate of the percent reductions are not available. More tests are underway to better determine the effect of ceramic engine coatings on diesel as well as gas fired engines.

Experience

According to MECA's report regarding emission control technology for stationary internal combustion engines from 1997, ceramic engine coatings have been used for almost 5 years in well over 200 stationary and mobile diesel engines.

Ignition/Injection Timing Retard

# Alternative Control Techniques Document: Stationary Diesel Engines

FINAL REPORT

EPA Contract No. EP-D-07-019
Work Assignment No. 2-07
EC/R Project No. MME-207

Prepared For: Energy

Strategies Group
U.S. Environmental Protection Agency (EPA)
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, NC 27711

Prepared By:

Bradley Nelson
EC/R Incorporated
501 Eastowne Drive, Suite 250
Chapel Hill, North Carolina 27514

March 5, 2010

Table 5-2. SCR Cost per Ton Summary for $NO_x$[a]

| Size Range (HP) | Average HP in Size Range (HP) | Average HP in Size Range (HP) | Uncontrolled $NO_X$ Emission Factor (lb/HP-hr)[b] | Uncontrolled $NO_X$ Emissions (Ton/year)[c] | Average Capital Cost ($) | Average Annualized Cost ($/year)[d] | Cost/Ton of $NO_X$ Removed ($/Ton)[e] |
|---|---|---|---|---|---|---|---|
| 50 – 100 | Tier 0 (pre- 1998) | | 1.52E-02 | 0.570 | | | $5,848 |
| | Tier 1 (1998-2003) | 75 | 1.23E-02 | 0.463 | $7,350 | $3,000 | $7,199 |
| | Tier 2 (2004-2007) | | 1.04E-02 | 0.389 | | | $8,569 |
| | Tier 3 (2008-2011) | | 6.61E-03 | 0.248 | | | $13,441 |
| 175 - 300 | Tier 0 (pre- 1996) | | 1.85E-02 | 2.20 | | | $4,808 |
| | Tier 1 (1996-2002) | 238 | 1.23E-02 | 1.46 | $23,324 | $9,520 | $7,245 |
| | Tier 2 (2003-2005) | | 8.82E-03 | 1.05 | | | $10,074 |
| | Tier 3 (2006-2010) | | 5.51E-03 | 0.656 | | | $16,125 |
| 600 - 750 | Tier 0 (pre- 1996) | | 1.85E-02 | 6.24 | | | $4,808 |
| | Tier 1 (1996-2001) | 675 | 1.28E-02 | 4.33 | $66,150 | $27,000 | $6,928 |
| | Tier 2 (2002-2005) | | 9.04E-03 | 3.05 | | | $9,836 |
| | Tier 3 (2006-2010) | | 5.51E-03 | 1.86 | | | $16,129 |
| >750 | Tier 0 (pre- 1996) | | 1.85E-02 | 9.25 | | | $4,805 |
| | Tier 1 (1996-2001) | 1,000 | 1.28E-02 | 6.40 | $98,000 | $40,000 | $6,944 |
| | Tier 2 (2002-2005) | | 9.04E-03 | 4.52 | | | $9,833 |
| | Tier 3 (2006-2010) | | 5.51E-03 | 2.76 | | | $16,103 |

[a] Costs are expressed in 2005 dollars.
[b] Table A2 of Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling – Compression Ignition (EPA420-P-04-009), April 2004.
[c] Uncontrolled emissions were calculated using the average HP in the range and assuming 1,000 hours of operation.
[d] The annualized cost is calculated assuming a 15 year equipment life and 7% interest.
[e] The cost/ton was calculated assuming 90 percent $NO_X$ reduction by the SCR.

### 4.3.2 Potential Pollutant Reductions

The CARB found that approximately 30 percent of the total PM mass of diesel exhaust are liquid hydrocarbons, or SOF.[10] Under certain operating conditions, DOCs have achieved SOF removal efficiencies of 80 to 90 percent. Therefore, the overall PM emission reduction is often cited at 20 to 50 percent.[11] Actual emission reductions vary however, as a result of engine type, size, age, duty cycle, condition, maintenance procedures, baseline emissions, test procedure, product manufacturer and the fuel sulfur level. In addition, DOCs have been verified to reduce emissions of CO and THC by as much as 90 percent.

### 4.3.3 Potential Issues/Problems with DOCs

The DOC is designed as a flow-through device with the catalytic reaction occurring on the surface of the honeycomb structure. Therefore, DOC devices are not as easily affected by the higher PM emissions rates from older engines. However, these devices should be monitored to ensure that the catalyst does not become blocked.

High sulfur concentrations in diesel fuel may affect the performance of the DOC control device. At high temperatures, $SO_2$ can oxidize to form sulfates. The sulfates contribute to increasing the PM emissions from the engine exhaust. As a result, some manufacturers recommend a maximum sulfur content of 500 parts per million or less to maintain the durability and performance of the DOC.[12]

Several chemical elements, such as phosphorous, lead and heavy metals, may also damage the catalyst in the DOC. Some of these elements can be found in engine lube oils. Therefore, some manufacturers recommend the use of low-phosphorous oils that contain less of these elements when using a DOC.

## 4.4 Flow-Through Filter

Flow-through filters (FTF) or partial filters is another technology that reduces the emission of PM from the diesel exhaust stream. This technology can be retrofit on most

### 4.1.2 Potential Pollutant Reductions

Verifications by CARB have shown that a number of diesel particulate filter systems are able to achieve at least 85 percent reduction of PM from on-road, off-road and stationary diesel engines. CARB reports PM emission reductions of 85 to 97 percent for various types of verified DPF or CDPFs.[6] The EPA has verified DPF and CDPF systems that achieve up to 90 percent reduction. In addition to the PM reductions, the CDPF filter also reduces emissions of CO and THC by 90 percent but requires sufficient exhaust temperatures to facilitate regeneration by the catalyst. These reductions have been verified by both the CARB and EPA diesel control technology verification programs.

### 4.1.3 Potential Problems/Issues with DPF/CDPF

Some potential issues that can affect the performance of DPFs and CDPFs include: PM loading, exhaust temperature, amount of sulfur in the fuel, and maintenance. Each of these parameters should be taken into account when purchasing the DPF or CDPF. There may be a slight fuel penalty with the installation of a DPF or CDPF.

The PM emission rates from older model year engines may overload the DPF storage capability, causing the unit to plug. This may be especially true for engines built prior to the Tier 1 nonroad emission standards. Special designs of the DPF with additional heating elements may be incorporated into the unit to ensure complete oxidation of the PM. In other active system designs, manufacturers use a diesel fuel burner upstream of the DPF to heat up the exhaust to sufficient temperatures to oxidize the PM.

Exhaust gas temperature also has an effect on the performance of the CDPF and DPF. For DPF systems, the exhaust gas temperature needs to be approximately 500°C to regenerate the filter substrate. At lower temperatures, the potential for the DPF to plug increases due to the inability of all of the collected PM to oxidize. Installing an active DPF, which includes a secondary heating source, will alleviate problems with exhaust temperatures below 500°C. For CDPF systems, the exhaust temperature needs to be in the range of 250°C to 300°C. At exhaust

### 4.4.2 Potential Pollutant Reductions for FTF

A manufacturer of this technology has been verified by CARB to provide Level 2 PM reductions of 50 percent on 1991-2002 on-road diesel engines. Recently, a manufacturer of an FTF has been conditionally verified by EPA. Several manufacturer also market verified FTF technology for use with stationary engines. The Manufacturers of Emissions Control Association (MECA) stated that flow-through systems are capable of achieving PM reductions of about 30 to 75 percent.[15] A catalyzed FTF can offer similar co-benefits of PM reduction as well as THC and CO reduction as discussed for CDPFs. At least one manufacturer has demonstrated a 90 percent reduction in THC and CO in conjunction with a 50 percent reduction in PM emissions that combines a DOC with a metal flow-through filter.

### 4.4.3 Potential Issues/Problems with FTF

There is limited experience with the use of FTF technology on stationary diesel engines. The FTF technology is less susceptible than other filtration systems to plugging or blockage of the exhaust gas channels when used on engines with high PM emissions. Manufacturers of FTF systems noted that visible smoke is normal from the FTF during periods when the stationary diesel engine shifts from low- to high-speed operation or high- to low-speed operation. If black smoke is visible during steady speed operation, the injectors need to be serviced or replaced.

## 4.5 Exhaust Gas Recirculation

Exhaust gas recirculation (EGR) is a $NO_X$ emissions reduction technique that works by lowering the combustion temperature and reducing the oxygen content of the combustion air. This technology has been applied by manufacturers to new engines to meet the diesel engine NSPS standards. It has also been used on new mobile source engines. Further, there are some verified EGR technologies that can be retrofitted to older engines. The verified technologies also include the incorporation of a DPF to remove PM from the recirculated exhaust gas. Low-pressure and high-pressure EGR systems have been applied to diesel engines, however the low-pressure EGR is most suitable for retrofit applications because it does not require engine modifications.[16]

### 5.2.2 Control Costs for CDPF

#### 5.2.2.1 Capital Costs

Control costs developed for the RICE NESHAP[9] were used to provide capital cost estimates for stationary diesel engine CDPF applications. These capital cost estimates were calculated using from a study that provided average equipment cost data from stationary diesel engine retrofits ranging from 40 HP to 1,400 HP. A linear regression of the cost data and horsepower size of the stationary engines provided the following capital cost formula:

$$y = 63.4(x) + 5{,}699$$

where;
x = engine size in HP, and
y = total capital cost for CDPF in 2008 dollars.

#### 5.2.2.2 Annual Costs

The RICE NESHAP control cost memorandum also provided the annual cost for retrofitting a CDPF on a stationary diesel engine. The annual cost was calculated using operating and maintenance costs provided in a control cost study for stationary diesel engines ranging from 40 HP to 1,400 HP. Using these data, and assuming a 10-year equipment life, the linear regression of the annual cost data provided the following annual cost formula:

$$y = 11.6(x) + 1{,}414$$

where;
x = engine size in HP, and
y = total annualized cost for CDPF in 2008 dollars.

#### 5.2.2.3 CDPF Cost per Ton of PM and THC Removed

Most vendors of the CDPF technology guarantee a 90 percent reduction efficiency in both PM and THC for diesel engines; this reduction was used to calculate the cost per ton reduced in this section. The cost per ton estimations for PM, CO, and THC are presented in

#### 5.2.3.2 Annual Costs

The annual cost for retrofitting a stationary diesel engine with a DOC was provided in the RICE NESHAP control cost memorandum. In the memorandum, the annual cost was calculated using operation and maintenance cost data collected in the control technology study. Using this cost data and assuming a 10-year equipment life, the linear regression formula was calculated to be;

$$y = 4.99(x) + 480$$

where;
x = engine size in HP, and
y = total annualized cost for DOC in 2008 dollars.

#### 5.2.3.3 DOC Cost per Ton of PM, CO, and THC Removed

Most vendors of the DOC technology guarantee 90 percent emission reduction efficiency for both CO and THC, and a 30 percent emission reduction in PM. These reductions were applied to the uncontrolled emission factors for each of these pollutants to calculate the cost per ton based on 1,000 hours per year engine operation; this information is presented in Tables 5-6, 5-7, and 5-8. The pollutant cost per ton values ranged from $14,394 to $85,354 per ton of PM reduced, $713 to $4,280 per ton of CO reduced, and $2,834 to $37,061 per ton of THC reduced. Using the data from the tables, the cost per ton for controlling all three pollutants is $1,442 for a 75 HP diesel engine (Tier 0) and $548 for a 1,000 HP diesel engine (Tier 0).

### 5.2.4 Control Costs for FTF

#### 5.2.4.1 Capital Costs

Capital cost estimates for diesel engine FTF applications were provided by a vendor of FTF control technologies.[10] The vendor provided cost data for three different sized engines, 75 HP, 238 HP, and 675 HP. These data and the EPA cost methodology were used to calculate an equation to be applied to all engines in the range. Based on the data the capital cost was estimated using the following linear regression formula;

$$y = 22.7(x) + 6{,}057$$

where;
x = engine size in HP, and
y = total capital cost for FTF.

#### 5.2.4.2 Annual Costs

The annual cost for retrofitting a stationary diesel engine with a FTF was calculated using the equipment information provided by the vendor and the EPA control cost methodology. For purposes of this document, it was assumed that there are no direct annual cost (i.e., no maintenance or operating costs), and the indirect annual cost was calculated assuming a 5-year equipment life for the FTF. Using these assumptions, the annual cost was calculated to be;

$$y = 2.89(x) + 772$$

where;
x = engine size in HP, and
y = total annualized cost for FTF.

#### 5.2.4.3 FTF Cost per Ton of PM Removed

Most vendors of the FTF technology guarantee 50 percent emission reduction efficiency in PM. This reduction was applied to the uncontrolled emission factor for PM to calculate the cost per ton based on 1,000 hours per year engine operation; this information is presented in Table 5-8. The PM cost per ton values range from $16,533 to $99,899. One manufacturer of the FTF system has included an oxidation catalyst to their design which reduces CO and THC

Public Hearing to Consider the Adoption of the Airborne Toxic Control Measure to Reduce Diesel Particulate Matter Emissions from Stationary Engines

(Continued from the December 11, 2003 ARB Board Meeting)

February 26, 2004

California Environmental Protection Agency

Air Resources Board

## ATCM Development Process

- Began process in 2001
- Held eight Public Workshops
- Coordination with CAPCOA Working Group
- Ongoing consideration of verbal and written comments
- Two Public Board Meetings: November and December 2003

## Estimated Cost Impacts Associated with Compliance Options

- Capital Costs
  - Diesel Particulate Filter: $38/hp
  - Diesel Oxidation Catalyst: $10/hp
  - New Engine: $93/hp
- Cost Savings for Emergency Standby Engines
  - Reduce hours of operation: fuel savings
- Cost-Effectiveness
  - $15/lb. of diesel PM reduced

## Air Quality Benefits Include Reduced Diesel PM and Criteria Pollutant Emissions

- An 80% reduction in diesel PM by 2020
- Avoid 121 premature deaths
- Reduced cancer risk to all receptors reduced

**BOWIE POWER STATION**
**COOLING OPTIONS**
**POWER PRODUCTION**

Kiewit Power Engineers -- MMR Bowie

| | | Wet Cooling | | | Hybrid Cooling | | | Dry Cooling | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 10 $^oF$ | 59 $^oF$ | 102 $^oF$ | 10 $^oF$ | 59 $^oF$ | 102 $^oF$ | 10 $^oF$ | 59 $^oF$ | 102 $^oF$ |
| Net Plant Output w/ Step-Up Xfmr Losses | kW | 600,340 | 567,713 | 531,890 | 601,441 | 564,482 | 505,655 | 603,569 | 567,838 | 506,959 |
| Net Plant Heat Rate (HHV) w/ Step-Up Xfmr Losses | Btu/kWh | 7,178 | 7,172 | 7,264 | 7,164 | 7,213 | 7,641 | 7,139 | 7,171 | 7,622 |

| | | **10$^o$F** | **59$^o$F** | **102$^o$F** | **Differential with Wet Cooling 102 $^oF$** |
|---|---|---|---|---|---|
| Net Plant Output (kW) | Dry | 603,569 | 567,838 | 506,959 | -4.7% |
| | Hybrid | 601,441 | 564,482 | 505,655 | -4.9% |
| | Wet | 600,340 | 567,713 | 531,890 | |

| | | **10$^o$F** | **59$^o$F** | **102$^o$F** | **Differential with Wet Cooling 102 $^oF$** |
|---|---|---|---|---|---|
| Net Plant Heat Rate (HHV) Btu/kWh | Dry | 7,139 | 7,171 | 7,622 | 4.9% |
| | Hybrid | 7,164 | 7,213 | 7,641 | 5.2% |
| | Wet | 7,178 | 7,172 | 7,264 | |

**BOWIE POWER STATION**
**HYBRID COOLING TOWER PM/$PM_{10}$/$PM_{2.5}$ EMISSIONS**

| | | | |
|---|---|---|---|
| Drift | 0.0005% | | same as Bowie 9 cell tower |
| Flowrate | 61,822 | gallons/minute | provided by Kiewit |
| TDS in Blowdown ($ppm_w$) | 4,039 | $ppm_w$ | same as Bowie 9 cell tower |
| TDS in blowdown (mg/l) [$ppm_w$ approximately = mg/l] | 4,039 | mg/l | |
| Flow of dissolved solids (lbs/gallon) | 0.03 | lbs/gallon | |
| Peak Drift (gallons/minute) | 0.31 | gallons/minute | |

| Pollutant | % of PM[a] | Hourly Emissions (lb/hour) | Annual Emissions (tpy) |
|---|---|---|---|
| PM | | 0.63 | 2.74 |
| $PM_{10}$ | 67.47 | 0.42 | 1.85 |
| $PM_{2.5}$ | 32.15 | 0.20 | 0.88 |

[a]The % of PM is calculated based on the TDS in blowdown and the droplet size diameter associated with the drift eliminators. It is assumed that the wet portion of the hybrid cooling system would have the same blowdown TDS and drift eliminators as the wet cooling system. As a result, the % of PM would be the same and the values shown in this column are from the spreadsheet "Bowie Power Station, Cooling Tower PM/$PM_{10}$/$PM_{2.5}$ Emissions".

For water ppm = mg/liter

lb/gallon is calculated as follows:

$$\frac{\text{lb}}{\text{gallon}} = \frac{\text{mg}}{\text{liter}} \times \frac{3.79\text{ liters}}{\text{gallons}} \times \frac{\text{grams}}{1000\text{ mg}} \times \frac{\text{lb}}{453.69\text{ grams}}$$

Peak drift in gallons/minute is calculated as follows:

$$\text{drift}\ \frac{\text{gallons}}{\text{minute}} = \text{tower flowrate}\ \frac{\text{gallons}}{\text{minute}} \times \frac{\%\text{ drift}}{100}$$

Emissions from Tower in lbs/hour is calculated as follows:

$$\frac{\text{lbs}}{\text{hour}} = \text{dissolved solids}\ \frac{\text{lbs}}{\text{gallon}} \times \text{drift}\ \frac{\text{gallons}}{\text{minute}} \times \frac{60\text{ minutes}}{\text{hour}}$$

Particulate Emissions from Tower in tons/year is calculated as follows:

$$\frac{\text{tons}}{\text{year}} = \frac{\text{lb}}{\text{hour}} \times \frac{8760\text{ hours}}{\text{year}} \times \frac{\text{tons}}{2000\text{ lb}}$$

$PM_{10}$ and $PM_{2.5}$ Emissions are Calculated as follows:

$$PM_{10}\ \text{Emissions} = \text{PM Emissions} \times \frac{\%\ PM_{10}}{100}$$

$$PM_{2.5}\ \text{Emissions} = \text{PM Emissions} \times \frac{\%\ PM_{2.5}}{100}$$

# BOWIE POWER STATION
# COOLING OPTIONS
# PM/PM10/PM2.5 EMISSIONS - LB/MW HOUR

Note that emissions are for the entire plant - 2 turbines and duct burners plus the cooling system

**PM**

| | Wet Cooling | | | Hybrid Cooling | | | Dry Cooling | | |
|---|---|---|---|---|---|---|---|---|---|
| | **10°F** | **59°F** | **102°F** | **10°F** | **59°F** | **102°F** | **10°F** | **59°F** | **102°F** |
| Maximum Net Electricity Production (kW) | 600,340 | 567,713 | 531,890 | 601,441 | 564,482 | 505,655 | 603,569 | 567,838 | 506,959 |
| Turbines and Duct Burners- PM Emissions (lb/hour) | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 |
| Cooling Tower - PM Emissions (lb/hour) | 1.29 | 1.29 | 1.29 | 0.63 | 0.63 | 0.63 | 0.00 | 0.00 | 0.00 |
| Total - PM Emissions (lb/hour) | 9.79 | 9.79 | 9.79 | 9.13 | 9.13 | 9.13 | 8.50 | 8.50 | 8.50 |
| Emission Rate (lb/MW*hour) | 0.016 | 0.017 | 0.018 | 0.015 | 0.016 | 0.018 | 0.014 | 0.015 | 0.017 |

**$PM_{10}$**

| | Wet Cooling | | | Hybrid Cooling | | | Dry Cooling | | |
|---|---|---|---|---|---|---|---|---|---|
| | **10°F** | **59°F** | **102°F** | **10°F** | **59°F** | **102°F** | **10°F** | **59°F** | **102°F** |
| Maximum Net Electricity Production (kW) | 600,340 | 567,713 | 531,890 | 601,441 | 564,482 | 505,655 | 603,569 | 567,838 | 506,959 |
| Turbines and Duct Burners- PM Emissions (lb/hour) | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 |
| Cooling Tower - $PM_{10}$ Emissions (lb/hour) | 0.87 | 0.87 | 0.87 | 0.42 | 0.42 | 0.42 | 0.00 | 0.00 | 0.00 |
| Total - $PM_{10}$ Emissions (lb/hour) | 9.37 | 9.37 | 9.37 | 8.92 | 8.92 | 8.92 | 8.50 | 8.50 | 8.50 |
| Emission Rate (lb/MW*hour) | 0.016 | 0.017 | 0.018 | 0.015 | 0.016 | 0.018 | 0.014 | 0.015 | 0.017 |

**$PM_{2.5}$**

| | Wet Cooling | | | Hybrid Cooling | | | Dry Cooling | | |
|---|---|---|---|---|---|---|---|---|---|
| | **10°F** | **59°F** | **102°F** | **10°F** | **59°F** | **102°F** | **10°F** | **59°F** | **102°F** |
| Maximum Net Electricity Production (kW) | 600,340 | 567,713 | 531,890 | 601,441 | 564,482 | 505,655 | 603,569 | 567,838 | 506,959 |
| Turbines and Duct Burners- PM Emissions (lb/hour) | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 | 8.50 |
| Cooling Tower - $PM_{2.5}$ Emissions (lb/hour) | 0.42 | 0.42 | 0.42 | 0.20 | 0.20 | 0.20 | 0.00 | 0.00 | 0.00 |
| Total - PM2.5 Emissions (lb/hour) | 8.92 | 8.92 | 8.92 | 8.70 | 8.70 | 8.70 | 8.50 | 8.50 | 8.50 |
| Emission Rate (lb/MW*hour) | 0.015 | 0.016 | 0.017 | 0.014 | 0.015 | 0.017 | 0.014 | 0.015 | 0.017 |

Turbine and duct burner emission rates are from "Bowie Power Station Turbine and Duct Burner Hourly Emission Rates" spreadsheet

Wet cooling tower emission rates are from "Bowie Power Station Cooling Tower PM/$PM_{10}$/$PM_{2.5}$ Emissions" spreadsheet

Hybrid cooling emission rates are from "Bowie Power Station Hybrid Cooling Tower PM/$PM_{10}$/$PM_{2.5}$ Emissions" spreadsheet

$$\frac{\text{lb}}{\text{MW*hour}} = \frac{\text{lb}}{\text{hour}} \times \frac{1}{\text{kW}} \times \frac{1{,}000\ \text{kW}}{1\ \text{MW}}$$

# BOWIE POWER STATION
# COOLING OPTIONS
# PM/PM10/PM2.5 EMISSIONS - TONS/YEAR

**$PM/PM_{10}/PM_{2.5}$ Emissions Per Turbine Duct Burner Pair**

| | tons/year |
|---|---|
| Startup Emissions | 1.06 |
| Turbine + Duct Firing | 17.95 |
| Turbine | 11.97 |
| Shutdown | **0.30** |
| **Total** | **31.27** |

| | PM | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|---|
| | tons/year | | |
| Wet Cooling Tower | 5.67 | 3.83 | 1.82 |
| | lb/hour | | |
| Hybrid Cooling Tower | 0.63 | 0.42 | 0.20 |
| | tons/year | | |
| | 2.74 | 1.85 | 0.88 |

| | PM | $PM_{10}$ | $PM_{2.5}$ |
|---|---|---|---|
| Total Dry Cooling | 62.54 | 62.54 | 62.54 |
| Total Hybrid Cooling | 65.28 | 64.39 | 63.42 |
| Total Wet Cooling | 68.21 | 66.37 | 64.36 |
| Difference between Wet and Dry | 5.67 | 3.83 | 1.82 |
| Difference between Wet and Hybrid | 2.93 | 1.98 | 0.94 |

Turbine emissions are from spreadsheet "Bowie Power Station Turbine and Duct Burner Annual Emissions"

Wet cooling tower emission rates are from "Bowie Power Station Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emissions" spreadsheet

Hybrid cooling tower emission rates are from "Bowie Power Station Hybrid Cooling Tower $PM/PM_{10}/PM_{2.5}$ Emissions" spreadsheet

$$\text{Hybrid Cooling Tower Emissions } \frac{\text{tons}}{\text{year}} = \text{Hybrid Cooling Tower Emissions } \frac{\text{lb}}{\text{hour}} \times 8760 \frac{\text{hours}}{\text{year}} \times \frac{\text{tons}}{2000\text{ lb}}$$

Note cooling tower emissions for the project have been calculated assuming a 100% capacity factor

$$\text{Wet and Hybrid Cooling Emissions } \frac{\text{tons}}{\text{year}} = (\text{Turbine and Duct Burner Pair Emissions } \frac{\text{tons}}{\text{year}} \times 2 \text{ turbine and duct burners}) + \text{Cooling Tower Emissions } \frac{\text{tons}}{\text{year}}$$

$$\text{Dry Cooling Emissions } \frac{\text{tons}}{\text{year}} = \text{Turbine and Duct Burner Pair Emissions } \frac{\text{tons}}{\text{year}} \times 2 \text{ turbine and duct burners}$$

## BOWIE POWER STATION
## COOLING OPTIONS
## $NO_x$, CO, VOC, $SO_2$ AND GREENHOUSE GAS LB/MW* HOUR EMISSIONS

| | Wet Cooling | | | Hybrid Cooling | | | Dry Cooling | | |
|---|---|---|---|---|---|---|---|---|---|
| | 10°F | 59°F | 102°F | 10°F | 59°F | 102°F | 10°F | 59°F | 102°F |
| Maximum Net Electricity Production (kW) | 600,340 | 567,713 | 531,890 | 601,441 | 564,482 | 505,655 | 603,569 | 567,838 | 506,959 |
| Net Plant Heat Rate (HHV) (Btu/kWh) | 7,178 | 7,172 | 7,264 | 7,164 | 7,213 | 7,641 | 7,139 | 7,171 | 7,622 |
| Turbine and Duct Burner- $NO_x$ Emissions (lb/hour) | 31.20 | 29.40 | 28.00 | 31.20 | 29.40 | 28.00 | 31.20 | 29.40 | 28.00 |
| $NO_x$ Emission Rate (lb/MW*hour) | 0.052 | 0.052 | 0.053 | 0.052 | 0.052 | 0.055 | 0.052 | 0.052 | 0.055 |
| Turbine and Duct Burner- CO Emissions (lb/hour) | 19.00 | 18.00 | 17.00 | 19.00 | 18.00 | 17.00 | 19.00 | 18.00 | 17.00 |
| CO Emission Rate (lb/MW*hour) | 0.032 | 0.032 | 0.032 | 0.032 | 0.032 | 0.034 | 0.031 | 0.032 | 0.034 |
| Turbine and Duct Burner- VOC Emissions (lb/hour) | 8.20 | 8.00 | 7.60 | 8.20 | 8.00 | 7.60 | 8.20 | 8.00 | 7.60 |
| VOC Emission Rate (lb/MW*hour) | 0.014 | 0.014 | 0.014 | 0.014 | 0.014 | 0.015 | 0.014 | 0.014 | 0.015 |
| Turbine and Duct Burner- $SO_2$ Emissions (lb/hour) | 8.20 | 7.60 | 7.20 | 8.20 | 7.60 | 7.20 | 8.20 | 7.60 | 7.20 |
| $SO_2$ Emission Rate (lb/MW*hour) | 0.014 | 0.013 | 0.014 | 0.014 | 0.013 | 0.014 | 0.014 | 0.013 | 0.014 |

| | $CO_2$[a] (kg/mmBtu) | $CH_4$[b] (kg/mmBtu) | $N_2O$[b] (kg/mmBtu) |
|---|---|---|---|
| Emission Factor | 53.06 | 1.00E-03 | 1.00E-04 |
| Global Warming Potential[c] | 1 | 21 | 310 |

[a]From 40 Code of Federal Regulations 98, Table C-1, "Default CO2 Emission Factors and High Heat Values for Various Types of Fuel".

[b]From 40 Code of Federal Regulations 98, Table C-2, "Default CH4 and N2O Emission Factors for Various Types of Fuel".

[c]From 40 CFR 98, Table A-1 "Global Warming Potentials"

| | Wet Cooling | | | Hybrid Cooling | | | Dry Cooling | | |
|---|---|---|---|---|---|---|---|---|---|
| | 10°F | 59°F | 102°F | 10°F | 59°F | 102°F | 10°F | 59°F | 102°F |
| Turbine and Duct Burner - $CO_2$ Emissions (lb/MW*hour) | 837.90 | 837.20 | 847.94 | 836.30 | 842.01 | 891.98 | 833.33 | 837.09 | 889.68 |
| Turbine and Duct Burner - $CH_4$ Emissions (lb/MW*hour) | 0.016 | 0.016 | 0.016 | 0.016 | 0.016 | 0.017 | 0.016 | 0.016 | 0.017 |
| Turbine and Duct Burner - $N_2O$ Emissions (lb/MW*hour) | 0.0016 | 0.0016 | 0.0016 | 0.0016 | 0.0016 | 0.0017 | 0.0016 | 0.0016 | 0.0017 |
| Turbine and Duct Burner - $CO_2$ Equivalents (lb/MW*hour) | 838.72 | 838.02 | 848.77 | 837.12 | 842.83 | 892.85 | 834.15 | 837.91 | 890.56 |

Maximum Net Electricity Production and Net Plant Heat Rate provided by Kiewit Power Engineers

lb/hour emissions are from spreadsheet "Bowie Power Station Combined Turbine and Duct Burner Hourly Emission Rates"

Emissions are for turbine operation with duct firing.

For $NO_x$, CO, VOC and $SO_2$ emissions:

$$\frac{\text{lb}}{\text{MW*hour}} = \frac{\text{lb}}{\text{hour}} \times \frac{1}{\text{kW}} \times \frac{1{,}000\ \text{kW}}{1\ \text{MW}}$$

For $CO_2$, $CH_4$, and $N_2O$

$$\frac{\text{lb}}{\text{MW*hour}} = \frac{\text{kg}}{\text{mmBtu}} \times \frac{\text{mmBtu}}{1{,}000{,}000\ \text{Btu}} \times \frac{\text{Btu}}{\text{kW hour}} \times \frac{1000\ \text{kW}}{\text{MW}} \times \frac{2.20\ \text{lb}}{\text{kg}}$$

$CO_2$ Equivalents

$$\frac{\text{lb}}{\text{MW*hour}} = \left(CO_2\ \frac{\text{lb}}{\text{MW*hour}} \times \text{Global Warming Potential}\right) + \left(CH_4\ \frac{\text{lb}}{\text{MW*hour}} \times \text{Global Warming Potential}\right) + \left(N_2O\ \frac{\text{lb}}{\text{MW*hour}} \times \text{Global Warming Potential}\right)$$

# BOWIE POWER STATION
# COOLING OPTIONS
# PARASITIC POWER REQUIREMENTS

Data Provided by Kiewit Power Engineers

| | | Wet | | | Hybrid | | | Dry | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 10 | 59 | 102 | 10 | 59 | 102 | 10 | 59 | 102 |
| Boiler Feed Pumps | kW | 4,344 | 4,325 | 4,299 | 4,344 | 4,325 | 4,299 | 4,344 | 4,325 | 4,299 |
| HRSG Recirculation Pumps | kW | 73 | 43 | 25 | 43 | 26 | 0 | 43 | 41 | 0 |
| Condensate Pumps | kW | 732 | 734 | 730 | 734 | 736 | 735 | 739 | 734 | 744 |
| Circulating Water Pumps | kW | 2,622 | 2,623 | 2,623 | 1,420 | 1,420 | 1,420 | 0 | 0 | 0 |
| Cooling Tower Fans | kW | 2,625 | 2,598 | 2,607 | 957 | 1,609 | 1,549 | 0 | 0 | 0 |
| ACC Fans | kW | 0 | 0 | 0 | 1,599 | 2,890 | 2,681 | 1,993 | 4,843 | 4,492 |
| CTG Auxiliaries | kW | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| STG Auxiliaries | kW | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Miscellaneous | kW | 1,000 | 1,000 | 1,000 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 |
| Subtotal Auxiliary Power | kW | 12,497 | 12,423 | 12,385 | 11,447 | 13,356 | 13,033 | 9,469 | 12,293 | 11,885 |
| | | | | | | | | | | |
| Generator Step-up Transformer Losses | kW | 2,351 | 2,232 | 2,116 | 2,351 | 2,223 | 2,016 | 2,351 | 2,232 | 2,017 |
| Auxiliary Transformer Losses | kW | 250 | 248 | 248 | 229 | 267 | 261 | 189 | 246 | 238 |
| Subtotal Transformer Losses | kW | 2,601 | 2,480 | 2,363 | 2,580 | 2,490 | 2,277 | 2,540 | 2,477 | 2,254 |
| | | | | | | | | | | |
| Total Auxiliary Power and Transformer Losses | kW | 15,097 | 14,903 | 14,749 | 14,027 | 15,846 | 15,310 | 12,009 | 14,770 | 14,140 |

| | | | **10°F** | **59°F** | **102°F** |
|---|---|---|---|---|---|
| Subtotal Auxiliary Power | kW | Dry | 9,469 | 12,293 | 11,885 |
| | | hybrid | 11,447 | 13,356 | 13,033 |
| | | Wet | 12,497 | 12,423 | 12,385 |

# BOWIE POWER STATION
# COOLING OPTIONS
# WATER USE

| Cooling Option | Annual Average Water Use 5094 hours/year (gpm) | Annual Average Water Use 8760 hours/year (gpm) | % Difference from Wet Cooling |
|---|---|---|---|
| Wet Cooling | 2,750 | 4,729 | |
| Hybrid Cooling | 1,050 | 1,806 | 38.18% |
| Dry Cooling | 100 | 172 | 3.64% |

Annual average water use in gallons per minute was provided for operation 5094 hours/year. Cooling tower is being permitted with a 100% capacity factor. Calculate annual average water use for 8760 hours/year as follows:

$$\frac{\text{gallons}}{\text{minute}} \text{ for 8760 hours/year} = \frac{\text{gallons}}{\text{minute}} \text{ for 5094 hours/year} \times \frac{\text{8760 hours/year}}{\text{5094 hours/year}}$$

# BOWIE POWER STATION
# COOLING OPTIONS
# COST EFFECTIVENESS

| | |
|---|---|
| Interest Rate | 7 |
| Equipment Life (years) | 20 |
| Capital Recovery Factor | 0.094 |

**Annual Costs**

| | Construction Cost | Capital Recovery ($/year) | Operating Cost ($/year) | Total Annual Cost ($/year) |
|---|---|---|---|---|
| Dry Cooling | $ 46,603,355 | $ 4,399,027 | $ 354,285 | $ 4,753,312 |
| Hybrid Cooling | $ 47,296,974 | $ 4,464,500 | $ 1,000,979 | $ 5,465,479 |
| Wet Cooling | $ 28,694,667 | $ 2,708,574 | $ 1,531,838 | $ 4,240,411 |

| | Operating Cost Provided by Kiewit for 5094 hours per year ($/year) |
|---|---|
| Dry Cooling | $206,019 |
| Hybrid Cooling | $582,076 |
| Wet Cooling | $890,774 |

**Emission Reductions**

| | tons/year | | |
|---|---|---|---|
| | PM | $PM_{10}$ | $PM_{2.5}$ |
| Difference between Wet and Dry | 5.67 | 3.83 | 1.82 |
| Difference between Wet and Hybrid | 2.93 | 1.98 | 0.94 |

**Cost Effectiveness**

| | $/ton | | |
|---|---|---|---|
| | PM | $PM_{10}$ | $PM_{2.5}$ |
| Dry Cooling | $838,327 | $1,241,074 | $2,611,710 |
| Hybrid Cooling | $1,866,302 | $2,759,785 | $5,823,327 |

**Incremental Costs - Compared to Wet Cooling**

| | $/ton | | |
|---|---|---|---|
| | PM | $PM_{10}$ | $PM_{2.5}$ |
| Dry Cooling | $90,459 | $133,917 | $281,814 |
| Hybrid Cooling | $418,325 | $618,596 | $1,305,278 |

Capital Recover Factor calculated in accordance with "EPA Air Pollution Control Cost Manual", equation 2.8a (page 2-21):

$$\text{Capital Recover Factor} = \frac{(\text{interest rate} \times (1 + \text{interest rate})^{\text{equipment life}})}{((1 + \text{interest rate})^{\text{equipment life}} - 1)}$$

Cooling Options Costs provided by Kiewit Power

$$\text{Capital Recovery } \frac{\$}{\text{year}} = \text{Capital Investment } \$ \times \text{Capital Recovery Factor}$$

$$\text{Total Annual Cost } \frac{\$}{\text{year}} = \text{Capital Recovery } \frac{\$}{\text{year}} + \text{Operating Costs } \frac{\$}{\text{year}}$$

Operating and Maintenance Costs provided for operation 5094 hours/year. Cooling tower is being permitted with a 100% capacity factor. Assume costs are proportional to hours of operation and adjust as follows:

$$\frac{\$}{\text{year}} \text{ for 8760 hours/year} = \frac{\$}{\text{year}} \text{ for 5094 hours/year} \times \frac{\text{8760 hours/year}}{\text{5094 hours/year}}$$

Emission Reductions are from spreadsheet "Bowie Power Station, Cooling Options, PM/$PM_{10}$/$PM_{2.5}$ Emissions - Tons per Year"

$$\text{Cost Effectiveness } \frac{\$}{\text{ton}} = \frac{\text{Total Annual Cost (\$/year)}}{\text{Emission Reduction (tons/year)}}$$

$$\text{Incremental Cost } \frac{\$}{\text{ton}} = \frac{\text{Total Annual Cost Cooling Option \$/year - Total Annual Cost Cooling Base Option \$/year}}{\text{Emission Difference Between Options ton/year}}$$

EPA/452/B-02-001

# EPA AIR POLLUTION CONTROL COST MANUAL

Sixth Edition

EPA/452/B-02-001

January 2002

United States Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Annualization is a process similar to EUAC but is not limited to constant cash flows. It involves determining the net present value of each alternative equipment investment and then determining the equal (in nominal terms) payment that would have to be made at the end of each year to attain the same level of expenditure. In essence, annualization involves establishing an annual "payment" sufficient to finance the investment for its entire life, using the formula:

$$PMT = NPV\left(\frac{i}{1-(1+i)^{-n}}\right) \tag{2.7}$$

where *PMT* is the equivalent uniform payment amount over the life of the control, *n*, at an interest rate, *i*. *NPV* indicates the present value of the investment as defined above in equation 2.6.

Engineering texts call this payment the capital recovery cost (*CRC*), which they calculate by multiplying the *NPV* of the investment by the capital recovery factor (*CRF*):

$$CRC = NPV \times CRF \tag{2.8}$$

where *CRF* is defined according to the formula:

$$\mathrm{CRF} = \left(\frac{\mathrm{i}(1+\mathrm{i})^{\mathrm{n}}}{(1+\mathrm{i})^{\mathrm{n}}-1}\right) \tag{2.8a}$$

The *CRF* equation is a transformation of the *PMT* form in equation 2.7 and returns the same information. Table A.2 in Appendix A lists the *CRF* for discount rates between 5.5 percent and 15 percent for annualization periods from one to 25 years.

### 2.4.4.5 Other Financial Analysis Tools

Many firms make investment decisions based upon the return on investment (*ROI*) of the proposed capital purchase, rather than the magnitude of its net present value. In and of itself, the ROI of an investment opportunity is of little use. For most pollution control investments, *ROI* analysis does not provide much in the way of useful information because, like a payback analysis, it must have positive cash flows to work properly. Calculated by dividing annual net income by the investment's capital cost, results in a percentage of the investment that is returned each year. The decision rule one should apply for *ROI* analysis is if the resulting percentage is at least as large as some established minimum rate of return, then the investment would be worth while. However, different industries require different rates of return on investments, and even within an industry, many different rates can be found. Analysts should consult with their firm's financial officers or an industrial association to determine what percentage would apply.

**Kiewit**

Bowie Cooling Options Estimated Operations and Maintenance Costs

| Cooling Configura | Cooling Tower Chemicals ($/yr) | Water Treatment Chemicals ($/yr) | Average Water Usage (gpm) | Water Costs ($/yr) | Equipment Maintenance Costs ($/yr) | Additional Operator Costs ($/yr) | **Total Yearly Operations and Maintenance Costs ($/yr)** | **Auxiliary Power (kW)** |
|---|---|---|---|---|---|---|---|---|
| | Notes 1,2,3 | Notes 1,2,3 | Notes 1,2,3 | Note 4 | Note 5 | Note 6 | | Notes 7,8 |
| Conventional Coo | $225,000 | $387,758 | 2,750 | $28,016 | $50,000 | $200,000 | **$890,774** | **19,437** |
| Hybrid Cooling Sy | $112,500 | $193,879 | 1,050 | $10,697 | $65,000 | $200,000 | **$582,076** | **19,763** |
| Air Cooled Conde | $0 | $125,000 | 100 | $1,019 | $80,000 | - | **$206,019** | **20,088** |

Notes:

1. All yearly figures assume 5094 hours of operation at the conditions described below. Estimated hours were from the conditions given in the air permit.
2. Assumes average of worst case and normal water flowrates from 3/2/10 email from Steve Garrett to Gary Crane.
3. Design water from 4/30/08 used in determining system chemistry.
4. Assumes a groundwater cost of $0.002 / gallon.
5. Equipment maintenance costs are estimated at 5% of the approximate cooling equipimnt capital costs divided by an assumed plant life of 20 years.
6. Additional operator costs are associated with the chemistry and operation of water pretreatment equipment.
7. Auxiliary power is calculated from previous projects and does not include any component or plant margin. The detailed calculation is shown on the follo
8. Estimated auxiliary power assumes one (1) boiler feed pump per unit running during all operating scenarios.

Cooling Power Drift Eliminator Performance Comparisons

| RBLC ID | Company | Facility | Drift Eliminator Performance | Emission Limits | Comments |
|---|---|---|---|---|---|
| AR-0094 | SOUTHWEST ELECTRIC POWER COMPANY | JOHN W. TURK JR. POWER PLANT | 0.0005% | | |
| AZ-0047 | DOME VALLEY ENERGY PARTNERS | WELLTON MOHAWK GENERATING STATION | 0.0005% | | |
| AZ-0049 | ALLEGHENY ENERGY SUPPLY LLC | LA PAZ GENERATING FACILITY | 0.0005% | | |
| AZ-0053 | TUCSON ELECTRIC POWER | SPRNGERVILLE GENERATING STATION | 0.0005% | | |
| CA-1101 | CITY OF VICTORVILLE | VICTORIVLLE 2 HYBRID POWER PROJECT | 0.0005% | | |
| CA-1212 | CITY OF PALMDALE | PALMDALE HYBRID POWER PROJECT | 0.0005% | | |
| CA | DELTA ENERGY CENTER, LLC | DELTA ENERG CENTER | 0.0005% | | |
| CA | METCALF ENERGY CENTER, LLC | METCALF ENERGY CENTER | 0.0005% | | |
| CA | RUSSELL CITY ENERGY COMPANY, LLC | RUSSELL CITY ENERGY CENTER | 0.0005% | | |
| CO-0057 | PUBLIC SERVICE COMPANY OF COLORADO | COMANCHE STATION | 0.0005% | | |
| FL-0299 | PROGRESS ENERGY FLORIDA, INC | CRYSTAL RIVER POWER PLANT | 0.0005% | | |
| FL-0303 | FLORIDA POWER AND LIGHT COMPANY | FPL WEST COUNTY ENERGY CENTER UNIT 3 | 0.0005% | | |
| FL-0304 | FLORIDA MUNICIPAL POWER AGENCY | CANE ISLAND POWER PARK | 0.0005% | | |
| FL-0316 | PROGRESS ENERGY FLORIDA | LEVY NUCLEAR PLANT | 0.0005% | | |
| FL-0317 | FLORIDA POWER AND LIGHT COMPANY | FPL TURKEY POINT NUCLEAR PLANT | 0.0005% | | |
| FL-0323 | GAINESVILLE REGIONAL UTILITY (GRU) DEERHAVEN | GAINESVILLE RENEWABLE ENERGY CENTER | 0.0005% | | |
| GA-0141 | OGETHORPE POWER CORPORATION | WARREN COUNTY BIOMASS ENERGY FACILITY | 0.0005% | | |
| GA-0142 | OSCEOLA STEEL CO. | OSCEOLA STEEL CO. | 0.0005% | | |
| GA | EFFINGHAM COUNTY POWER, LLC | EFFINGHAM COUNTY POWER PLANT | 0.0005% | | |
| IA-0088 | ARCHER DANIELS MIDLAND | ADM CORN PROCESSING - CEDAR RAPIDS | 0.0005% | | |
| IA-0089 | HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672 | | 0.0005% | | |
| IA-0095 | TATE & LYLE INDGREDIENTS AMERICAS, INC. | | 0.0005% | | |
| IA-0105 | IOWA FERTILIZER COMPANY | IOWA FERTILIZER COMPANY | 0.0005% | | |
| IA-0106 | CF INDUSTRIES NITROGEN, LLC | CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX | 0.0005% | | |
| ID-0017 | SOUTHEAST IDAHO ENERGY, LLC | POWER COUNTY ADVANCED ENERGY CENTER | 0.0005% | | |
| IN-0158 | ST. JOSEPH ENERGY CENTER, LLC | ST. JOSEPH ENERGY CENTER, LLC | 0.0005% | | |
| IN-0167 | MAGNETATION LLC | MAGNETATION LLC | 0.0005% | | |

Cooling Power Drift Eliminator Performance Comparisons

| RBLC ID | Company | Facility | Drift Eliminator Performance | Emission Limits | Comments |
|---|---|---|---|---|---|
| LA-0231 | LAKE CHARLES COGENERATION, LLC | LAKE CHARLES GASIFICATION FACILITY | 0.0005% | | |
| LA-0254 | ENTERGY LOUISIANA LLC | NINEMILE POINT ELECTRIC GENERATING PLANT | 0.0005% | | |
| MD-0040 | COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC | CPV ST CHARLES | 0.0005% | | |
| MI-0400 | WOLVERINE POWER SUPPLY | WOLVERINE POWER | 0.0005% | | |
| MI-0401 | VC ENERGY LLC MIDLAND POWER | MIDLAND POWER STATION | 0.0005% | | |
| MT-0030 | CONOCOPHILLIPS COMPANY | BILLINGS REFINERY | 0.0005% | | |
| ND-0024 | GREAT RIVER ENERGY | SPIRITWOOD STATION | 0.0005% | | |
| NE-0031 | OMAHA PUBLIC POWER DISTRICT | OPPD - NEBRASKA CITY STATION | 0.0005% | | |
| NE-0046 | AVENTINE RENEWABLE ENERGY - AURORA WEST, LLC | | 0.0005% | | |
| NH-0018 | LAIDLAW BERLIN BIOPOWER, LLC | BERLIN BIOPOWER | 0.0005% | | |
| NJ | CPV SHORE LLC | WOODBRIDGE ENERGY CENTER | 0.0005% | | |
| NV-0036 | NEWMONT NEVADA ENERGY INVESTMENT, LLC | TS POWER PLANT | 0.0005% | | |
| NY-0093 | TRIGEN-NASSAU ENERGY CORPORATION | | 0.0005% | | |
| OH-0328 | V & M STAR | V & M STAR | 0.0005% | | |
| OH-0352 | OREGON CLEAN ENERGY CENTER | OREGON CLEAN ENERGY CENTER | 0.0005% | | |
| OR-0041 | DIAMOND WANAPA I, L.P. | WANAPA ENERGY CENTER | 0.0005% | | |
| TX-0295 | SOUTH TEXAS ELECTRIC COOPERATIVE INC | SAM RAYBURN GENERATION STATION | 0.0005% | | |
| TX-0551 | PANDA SHERMAN POWER LLC | PANDA SHERMAN POWER STATION | 0.0005% | | |
| TX-0552 | STARK POWER GENERATION II HOLDINGS, LLC | WOLF HOLLOW POWER PLANT NO. 2 | 0.0005% | | |
| TX-0553 | LINDALE RENEWABLE ENERGY LLC | | 0.0005% | | |
| VA | BRUNSWICK COUNTY POWER STATION | VIRGINIA ELECTRIC AND POWER COMPANY | 0.0005% | | |
| VA | GREEN ENERGY PARTNERS/STONEWALL, LLC | GREEN ENERGY PARTNERS/STONEWALL, LLC | 0.0005% | | |
| WA-0291 | WALLULA GENERATION, LLC | WALLULA POWER PLANT | 0.0005% | | |
| WI-0252 | SPECIALTY MINERALS INC. (SMI) | SPECIALTY MINERALS INC. - SUPERIOR | 0.0005% | | |
| WV-0024 | WESTERN GREENBRIER CO-GENERATION, LLC | | 0.0005% | | |
| WY-0072 | FMC WYOMING CORPORATION | GRANGER FACILITY | 0.0005% | | |
| CA | CAITHNESS BLYTHE II, LLC | BLYTHE II | 0.0006% | | |
| AR-0070 | GENOVA ARKANSAS I, LLC | | 0.001% | | |
| CA-1223 | PIO PICO ENERGY CENTER, LLC | PIO PICO ENERGY CENTER | 0.001% | | |

Cooling Power Drift Eliminator Performance Comparisons

| RBLC ID | Company | Facility | Drift Eliminator Performance | Emission Limits | Comments |
|---|---|---|---|---|---|
| FL-0284 | DEPARTMENT OF SOLID WASTE MANAGEMENT | HILLSBOROUGH COUNTY RESOURCE RECOVERY FACILITY | 0.001% | | |
| ID-0017 | SOUTHEAST IDAHO ENERGY, LLC | POWER COUNTY ADVANCED ENERGY CENTER | 0.001% | | |
| IN-0156 | STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION | STEEL DYNAMICS, INC. - STRUCTURAL AND RAIL DIVISION | 0.001% | | |
| MD-0032 | MIRANT MID-ATLANTIC, LLC | DICKERSON | 0.001% | | |
| MO-0081 | AMERICAN ENERGY PRODUCERS, INC. | AMERICAN ENERGY PRODUCERS, INC. | 0.001% | | |
| NV-0050 | MGM MIRAGE | | 0.001% | | |
| OK-0056 | MUSTANG POWER LLC | HORSESHOE ENERGY PROJECT | 0.001% | | |
| WA-0328 | BP WEST COAST PRODUCTS, LLC | BP CHERRY POINT COGENERATION PROJECT | 0.001% | | |
| WA-0329 | DARRINGTON ENERGY LLC | COGENERATION POWER PLANT | 0.001% | | |
| VA-0319 | GATEWAY GREEN ENERGY | GATEWAY COGENERATION 1 LLC - SMART WATER PROJECT | 0.001% | | |
| FL-0293 | PROGRESS ENERGY FLORIDA | CRYSTAL RIVER POWER PLANT | 0.002% | | |
| IN-0110 | COGENTRIX LAWRENCE CO., LLC | | 0.002% | | |
| TX-0549 | INEOS LLC | CHOCOLATE BAYOU FACILITY | 0.002% | | |
| WI-0228 | WISCONSIN PUBLIC SERVICE | WPS - WESTON PLANT | 0.002% | | |
| WV-0023 | LONGVIEW POWER, LLC | MAIDSVILLE | 0.002% | | Incorrectly list in RBLC. Operating Permit shows 0.0020% |
| LA-0206 | EXXONMOBIL REFINING & SUPPLY CO | BATON ROUGE REFINERY | 0.003% | | |
| OK-0055 | MUSTANG POWER LLC | MUSTANG ENERGY PROJECT | 0.004% | | |
| IA-0092 | SOUTHWEST IOWA RENEWABLE ENERGY | | 0.005% | | |
| IL-0102 | AVENTINE RENEWABLE ENERGY, INC. | | 0.005% | | |
| LA-0136 | THE DOW CHEMICAL COMPANY | PLAQUEMINE COGENERATION FACILITY | 0.005% | | |
| LA-0192 | CRESENT CITY POWER, LLC | | 0.005% | | |
| LA-0211 | MARATHON PETROLEUM CO LLC | GARYVILLE REFINERY | 0.005% | | |
| MN-0070 | MINNESOTA STEEL INDUSTRIES, LLC | | 0.005% | | |
| NE-0029 | ABENGOA BIOENERGY CORPORATION | YORK | 0.005% | | |
| NV-0047 | 99 CIVIL ENGINEER SQUADRON OF USAF | NELLIS AIR FORCE BASE | 0.005% | | |
| NV-0049 | HARRAH'S OPERATING COMPANY, INC. | | 0.005% | | |
| OH-0303 | ASALLIANCE BIOFUELS, LLC | ASALLIANCE BIOFUELS, LLC | 0.005% | | |
| OH-0341 | NUCOR STEEL | NUCOR STEEL MARION, INC. | 0.005% | | |
| WI-0207 | ACE ETHANOL, LLC | STANLEY | 0.005% | | |
| WY-0064 | BASIN ELECTRIC POWER COOPERATIVE | DRY FORK STATION | 0.005% | | |

Cooling Power Drift Eliminator Performance Comparisons

| RBLC ID | Company | Facility | Drift Eliminator Performance | Emission Limits | Comments |
|---|---|---|---|---|---|
| NC-0112 | NUCOR STEEL | | 0.008% | | |
| MN-0078 | SAPPI FINE PAPER PLC | SAPPI CLOQUET LLC | 0.02% | | |
| LA-0213 | VALERO REFINING - NEW ORLEANS, LLC | ST. CHARLES REFINERY | | | No emission limit |
| AL-0246 | HUNT REFINERY CO. | TUSCALOOSA | | 0.4 T/yr | |
| LA-0204 | SHINTECH LOUISIANA LLC | PLAQUEMINE PVC PLANT | | | listed in LB/MM gal |
| OH-0308 | SUNOCO, INC. | SUN COMPANY, INC., TOLEDO REFINERY | | 0.12lb/h | |
| OK-0135 | PRYOR PLANT CHEMICAL COMPANY | | | 1.12lb/h | |
| OK-0129 | ASSOCIATED ELECTRIC COOPERATIVE INC | CHOUTEAU POWER PLANT | | 0.4000lb/h/ cell | |
| OH-0317 | OHIO RIVER CLEAN FUELS, LLC | | | 2.4lb/h | |
| LA-0148 | RED RIVER ENVIRONMENTAL PRODUCTS LLC | ACTIVATED CARBON FACILITY | | 0.41lb/h | |
| AL-0242 | HUNT REFINING COMPANY | TUSCALOOSA REFINERY | | | No emission limits listed |
| OK-0124 | KOCH NITROGEN COMPANY | ENID NITROGEN PLANT | | | No emission limits listed |
| LA-0224 | SOUTHWEST ELECTRIC POWER COMPANY | ARSENAL HILL POWER PLANT | | 1.4lb/hr | listed in lb/h |
| LA-0221 | ENTERGY LOUISIANA LLC | LITTLE GYPSY GENERATING PLANT | | 0.05lb/hr | Drift eliminator with 99.9% control |
| FL-0294 | PROGRESS ENERGY FLORIDA | ANCLOTE POWER PLANT | | 108t/yr | |
| IA-0082 | GOLDEN GRAIN ENERGY | | | 1.33lb/h | |
| TX-0507 | NRG TEXAS | NRG COAL HANDLING PLANT | | 5.78lb/h | |
| NC-0101 | FORSYTH ENERGY PROJECTS, LLC | | | 0.002lb/h PM10, 0.007lb/h PM | |
| AZ-0046 | ARIZONA CLEAN FUELS YUMA LLC | | | 1.6lb/h | |
| TX-0487 | ROHM AND HAAS TEXAS INCORPORATION | LONE STAR PLANT | | 2.04lb/h | |
| OH-0252 | DUKE ENERGY HANGING ROCK, LLC | DUKE ENERGY HANGING ROCK ENERGY FACILITY | | 2.6lb/hr | listed in lb/h |
| LA-0191 | ENTERGY NEW ORLEANS, INC. | MICHOUD ELECTRIC GENERATING PLANT | | 0.052lb/h | Permit limits of 0.005% but eliminators designed to achieve 0.001% |

Cooling Power Drift Eliminator Performance Comparisons

| RBLC ID | Company | Facility | Drift Eliminator Performance | Emission Limits | Comments |
|---|---|---|---|---|---|
| TX-0451 | DIAMOND SHAMROCK REFINING COMPANY LP | | | 69.2lb/h | |
| OH-0254 | DUKE ENERGY NORTH AMERICA | DUKE ENERGY WASHINGTON COUNTY LLC | | 2.08lb/h | |
| TX-0458 | DUKE ENERGY LP | JACK COUNTY POWER PLANT | | 0.4lb/h PM10, 3.0lb/h PM | |
| TX-0374 | BP AMOCO CHEMICAL CO | CHOCOLATE BAYOU PLANT | | 0.54lb/h | |
| OK-0090 | DUKE ENERGY | DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY | | 1.2lb/h | |
| TX-0352 | BRAZOS VALLEY ENERGY LP | BRAZOS VALLEY ELECTRIC GENERATING FACILITY | | 1.58lb/h | |
| IA-0062 | INTERSTATE POWER & LIGHT (IPL) | EMERY GENERATING STATION | | 1.224lb/h | |
| TX-0407 | STEAG POWER LLC | STERNE ELECTRIC GENERATING FACILITY | | 1.01lb/h | |
| OH-0248 | CALPINE CORPORATION | LAWRENCE ENERGY | | 1.69lb/h | |
| CO-0052 | ROCKY MOUNTAIN ENERGY CENTER, LLC. | | | 0.42lb/MM gal | |
| IN-0114 | MIRANT SUGAR CREEK LLC | | | 1.41lb/hr | |
| NM-0044 | DUKE ENERGY CURRY LLC | CLOVIS ENERGY FACILITY | | 0.7lb/h | |
| MS-0055 | EL PASO MERCHANT ENERGY CO. | | | | |
| OK-0070 | GENOVA OKLAHOMA LLC | GENOVA OK I POWER PROJECT | | 0.307lb/h per cell | |
| OH-0264 | NORTON ENERGY STORAGE, LLC | | | 5.63lb/h | |
| OK-0072 | REDBUD ENERGY LP | REDBUD POWER PLT | | 3.17lb/h | |
| AR-0051 | DUKE ENERGY | JACKSON FACILITY | | 0.7lb/h | |
| NJ-0043 | LIBERTY GENERATING STATION | | | 1.81lb/h | |
| OH-0268 | Global Energy, Inc. | LIMA ENERGY COMPANY | | 1.88lb/h | |
| TX-0351 | SEI TEXAS LLC | WEATHERFORD ELECTRIC GENERATION FACILITY | | 1.45lb/h | |
| LA-0157 | PERRYVILLE ENERGY PARTNERS, LLC | PERRYVILLE POWER STATION | | 3.3lb/h | |
| AR-0052 | ARKANSAS ELECTRIC CO-OP | THOMAS B. FITZHUGH GENERATING STATION | | 0.4lb/h | |
| LA-0164 | ACADIA POWER PARTNERS | ACADIA POWER STATION | | 0.76lb/h | |
| TX-0350 | ENNIS-TRACTEBEL II LP | ENNIS TRACTEBEL POWER | | 0.5lb/h | |
| NC-0094 | GENPOWER EARLEYS, LLC | | | 2.01lb/h | |
| OH-0257 | JACKSON COUNTY POWER, LLC | | | 3.43lb/h | |
| MS-0058 | CHOCTAW GAS GENERATION, LLC | | | | |
| AR-0047 | HOT SPRINGS POWER PROJECT | | | 0.9lb/h | |

Cooling Power Drift Eliminator Performance Comparisons

| RBLC ID | Company | Facility | Drift Eliminator Performance | Emission Limits | Comments |
|---|---|---|---|---|---|
| TX-0233 | RELIANT ENERGY CHANNELVIEW LP | CHANNELVIEW COGENERATION FACILITY | | 0.18lb/h | |

Entries from the RBLC for new units with a permit issuance date 2002 - 2013
Information from state agency websites