SUPREME COURT
FILED

JUL 25 2012

Frank A. McGuire Clerk

Deputy

No. S194121

IN THE

SUPREME COURT OF CALIFORNIA

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**ELK HILLS POWER, LLC,**
**Plaintiff and Appellant,**

v.

**CALIFORNIA STATE BOARD OF EQUALIZATION AND COUNTY OF KERN,**
**Defendants and Respondents.**

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**After A Decision By The Court of Appeal**
**Fourth Appellate District, Division One, Case No. D056943,**
**San Diego Superior Court Case No. 37-2008-00097074-CU-MC-CTL**

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# APPELLANT'S MOTION REQUESTING JUDICIAL NOTICE

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*Elk Hills Power, LLC*

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**IN THE**

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*Attorneys for Plaintiff and Appellant*
*Elk Hills Power, LLC*

## MOTION REQUESTING JUDICIAL NOTICE

Pursuant to Rules 8.520(g) and 8.252 of the California Rules of Court, and Sections 452 and 459 of the Evidence Code, Appellant Elk Hills Power, LLC ("EHP") respectfully requests that the Court take judicial notice of the following nine (9) documents listed below, which are included as exhibits to the attached Declaration of Paul J. Mooney.

1. California Energy Commission Decision Application for Certification Elk Hills Power Project, Docket No. 99-AFC-1, (December, 2000), at pp.120-36.
2. United States Energy Information Administration – International Energy Outlook 2011 (September 19, 2011).
3. United States Energy Information Administration – Natural Gas 1998: Issues and Trends, Chapter 2, Natural Gas and the Environment.
4. United States Energy Information Administration – Annual Energy Outlook 2012 with Projections to 2035, pp.86-88.
5. San Joaquin Valley Air Pollution Control District Authority to Construct, Permit No. S-3523-1-2 (March 30, 2000).
6. San Joaquin Valley Air Pollution Control District Authority to Construct, Permit No. S-3523-2-2 (March 30, 2000).
7. California Energy Commission Order Approving Project Modification (March 19, 2003).
8. California Energy Commission Request to Amend the Elk Hills Power Project (99-AFC-1C) to Allow PM10 ERC Tendering and Commissioning Emissions Increase Staff Analysis (February 28, 2003).
9. California Energy Commission Proceeding's Main Page for the Elk Hills Power Plant Project.

The documents that are the subject of this Motion are offered in support of EHP's Consolidated Answer to Amicus Curiae Briefs In Support of Respondents, which is filed simultaneously herewith. These documents were not presented to the trial court nor to the Court of Appeal, and they do not relate to proceedings occurring after the judgment in the above-captioned matter. True and correct copies of each document are attached to the Declaration of Paul J. Mooney.

This Motion is made on the basis that Exhibits 1-9 are relevant to EHP's Consolidated Answer to Amicus Curiae Briefs Filed In Support of Respondents by the following entities: California State Association of Counties and California Assessors' Association, John R. Noguez, Los Angeles County Assessor, Natural Resources Defense Council, The Sierra Club, Middle Class Taxpayers Association of San Diego, and Climate Protection Campaign. These Amici have raised arguments that go beyond the scope of the record in this case, including arguments based on appraisal theory and environmental policy. EHP's response to these arguments requires reference to records of administrative agencies, including the United States Energy Information Administration, the California Energy Commission and the San Joaquin Valley Air Pollution Control District. The documents contained in Exhibits 1-9 are responsive to the arguments made by these Amici.

Evidence Code Section 452(c) permits courts to take judicial notice of "[o]fficial acts of the legislative, executive, and judicial departments of the United States and of any state of the United States." (Evid. Code § 452(c).) Official acts have been interpreted to include "records, reports and orders of administrative agencies." (*Ordlock v. Franchise Tax Bd.* (2006) 38 Cal.4th 897, 912 n.8 [quoting *Rodas v. Spiegel* (2001) 87 Cal.App.4th 513, 518].) Evidence Code 452(h) permits courts to take judicial notice of "[f]acts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy." (Evid. Code § 452(h).)

Exhibits 1 and 7-9 are official records of the California Energy Commission. Exhibits 2-4 are reports of the United States Energy Information Administration. Exhibits 5-6 are official records of the San Joaquin Valley Air Pollution Control District. Exhibits 1-9 all set forth facts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy, i.e. the federal or State administrative agencies themselves.

For these reasons, EHP respectfully requests that the Court take judicial notice of Exhibits 1-9. A proposed form of order is attached.

RESPECTFULLY SUBMITTED this 24th day of July, 2012.

LAW OFFICE of PETER MICHAELS

and

GIBSON, DUNN & CRUTCHER, LLP

and

MOONEY, WRIGHT & MOORE, PLLC

By: ______________________________

Paul J. Mooney (*Pro Hac Vice*)

*Attorneys for Plaintiff/Appellant EHP*

**<u>DECLARATION OF PAUL J. MOONEY</u>**

I, Paul J. Mooney, declare as follows:

1) I am an attorney duly licensed to practice in the State of Arizona and admitted *pro hac vice* for purposes of this matter. I am a partner in the law firm of Mooney, Wright & Moore, PLLC, co-counsel of record for Appellant Elk Hills Power, LLC ("EHP"). I submit this Declaration in support of EHP's Motion Requesting Judicial Notice, which accompanies this Declaration. I have personal knowledge of the matters set forth herein, except for those matters which are based upon information and belief, in which case I believe those matters to be true.

2) Attached hereto, incorporated herein by reference, and marked as Exhibit 1 is a true and correct copy of the California Energy Commission Decision Application for Certification Elk Hills Power Project, Docket No. 99-AFC-1, (December, 2000), pp. 120-136. I downloaded a copy of this document on July 19, 2012, from the following website:
http://www.energy.ca.gov/sitingcases/elkhills/documents/2000-12-22_DECISION.PDF.

3) Attached hereto, incorporated herein by reference, and marked as Exhibit 2 is a true and correct copy of the United States Energy Information Administration – International Energy Outlook 2011 (September 19, 2011). I downloaded a copy of this document on July 9, 2012, from the following website:
http://www.eia.gov/forecasts/ieo/electricity.cfm.

4) Attached hereto, incorporated herein by reference, and marked as

Exhibit 3 is a true and correct copy of the United States Energy Information Administration – Natural Gas 1998: Issues and Trends, Chapter 2, Natural Gas and the Environment. I downloaded a copy of this document on July 19, 2012, from the following website: http://www.eia.gov/oil_gas/natural_gas/analysis_publications/natural_gas_1998_issues_and_trends/it98.html.

5) Attached hereto, incorporated herein by reference, and marked as Exhibit 4 is a true and correct copy of the United States Energy Information Administration – Annual Energy Outlook 2012 with Projections to 2035, pp.86-88. I downloaded a copy of this document on July 19, 2012, from the following website: http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

6) Attached hereto, incorporated herein by reference, and marked as Exhibit 5 is a true and correct copy of the San Joaquin Valley Air Pollution Control District Authority to Construct, Permit No. S-3523-1-2 (March 30, 2000). I obtained a copy of this document from the San Joaquin Valley Air Pollution Control District on July 17, 2012, in response to a Public Records Request.

7) Attached hereto, incorporated herein by reference, and marked as Exhibit 6 is a true and correct copy of the San Joaquin Valley Air Pollution Control District Authority to Construct, Permit No. S-3523-2-2 (March 30, 2000). I obtained a copy of this document from the San Joaquin Valley Air Pollution Control District on July 17, 2012, in response to a Public Records Request.

8) Attached hereto, incorporated herein by reference, and marked as Exhibit 7 is a true and correct copy of the California Energy

Commission Order Approving Project Modification (March 19, 2003). I downloaded a copy of this document on July 9, 2012, from the following website:

http://www.energy.ca.gov/sitingcases/elkhills/compliance/2003-04-03_ORDER_APP.PDF.

9) Attached hereto, incorporated herein by reference, and marked as Exhibit 8 is a true and correct copy of the California Energy Commission Request to Amend the Elk Hills Power Project (99-AFC-1C) to Allow PM10 ERC Tendering and Commissioning Emissions Increase Staff Analysis (February 28, 2003). I downloaded a copy of this document on July 9, 2012, from the following website:

http://www.energy.ca.gov/sitingcases/elkhills/compliance/2003-02-28_PUB_REVIEW_EMISN.PDF.

10) Attached hereto, incorporated herein by reference, and marked as Exhibit 9 is a true and correct copy of the California Energy Commission Proceeding's Main Page the Elk Hills Power Plant Project. I downloaded a copy of this document on July 19, 2012, from the following website:

http://www.energy.ca.gov/sitingcases/elkhills/.

11) I declare under penalty of perjury under the laws of the State of Arizona that the foregoing is true and correct.

Executed this 24th day of July, 2012 in Maricopa County, Arizona.

By: ______________________

Paul J. Mooney

*Attorney for Appellant Elk Hills Power, LLC*

No. S194121

IN THE

SUPREME COURT OF CALIFORNIA

---

ELK HILLS POWER, LLC,
Plaintiff and Appellant,

v.

CALIFORNIA STATE BOARD OF EQUALIZATION AND COUNTY OF KERN,
Defendants and Respondents.

---

After A Decision By The Court of Appeal
Fourth Appellate District, Division One, Case No. D056943,
San Diego Superior Court Case No. 37-2008-00097074-CU-MC-CTL

---

[PROPOSED] ORDER

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Appellant Elk Hills Power, LLC ("EHP") filed a Motion Requesting Judicial Notice. Pursuant to Evidence Code Sections 452 and 459, the Court hereby grants EHP's Motion and judicially notices the following documents:

1. California Energy Commission Decision Application for Certification Elk Hills Power Project, Docket No. 99-AFC-1, (December, 2000), at pp.120-36.
2. United States Energy Information Administration – International Energy Outlook 2011 (September 19, 2011).

3. United States Energy Information Administration – Natural Gas 1998: Issues and Trends, Chapter 2, Natural Gas and the Environment

4. United States Energy Information Administration – Annual Energy Outlook 2012 with Projections to 2035, pp.86-88.

5. San Joaquin Valley Air Pollution Control District Authority to Construct, Permit No. S-3523-1-2 (March 30, 2000).

6. San Joaquin Valley Air Pollution Control District Authority to Construct, Permit No. S-3523-2-2 (March 30, 2000).

7. California Energy Commission Order Approving Project Modification (March 19, 2003).

8. California Energy Commission Request to Amend the Elk Hills Power Project (99-AFC-1C) to Allow PM10 ERC Tendering and Commissioning Emissions Increase Staff Analysis (February 28, 2003).

9. California Energy Commission Proceeding's Main Page for the Elk Hills Power Plant Project.

IT IS SO ORDERED.

Dated: ____________________ ______________________________
Presiding Justice

<u>**CERTIFICATE OF SERVICE BY MAIL**</u>

Elk Hills Power, LLC v. California State Board of Equalization, et al.

Court of Appeal No. D056943

Superior Court Case No. 37-2008-00097074-CU-MC-CTL

1. At the time of service I was at least 18 years of age and not a party to this legal action.

2. My business address is 1201 S. Alma School Rd., Ste. 16000, Mesa, AZ 85210.

3. On July 24, 2012, I enclosed copies of:

**Appellant's Motion Requesting Judicial Notice**

in envelopes and deposited the sealed envelopes with the U.S. Postal Service, with the postage full prepaid.

4. The envelopes were addressed as follows:

| |
|---|
| Tim Nader, Esq.<br>Deputy Attorney General<br>110 West A Street, Suite 1100<br>San Diego, CA 92101<br>*Attorneys for Defendant and Respondent, California State Board of Equalization*<br>(619) 645-2210 |
| Jerri S. Bradley, Esq.<br>Deputy County Counsel<br>County of Kern<br>1115 Truxtun Ave., 4th Floor<br>Bakersfield, CA 93301<br>*Attorney for Defendant and Respondent, Kern County*<br>(661) 868-3819 |

| |
|---|
| Kurt R. Wiese<br>Barbara Baird<br>South Coast Air Quality Management District<br>21865 Copley Drive<br>Diamond Bar, CA 91765<br>*Attorneys for Amicus Curiae South Coast Air Quality Management District* |
| Mardiros H. Dakessian<br>Margaret M. Grignon<br>Mike Shaikh<br>Reed Smith LLP<br>355 South Grand Avenue, Suite 2900<br>Los Angeles, CA 90071-1514<br>*Attorneys for Amicus Curiae Institute for Professionals in Taxation* |
| John R. Messenger<br>Reed Smith LLP<br>101 Second Street, Suite 1800<br>San Francisco, CA 94105<br>*Attorneys for Amicus Curiae Institute for Professionals in Taxation* |
| Peter H. Weiner<br>Gordon E. Hart<br>Sean D. Unger<br>Jill E.C. Yung<br>Paul Hastings, LLP<br>55 Second Street, 24th Floor<br>San Francisco, CA 94105<br>*Attorneys for Amicus Curiae Independent Energy Producers Association* |
| Nancy Iredale<br>Jeffrey G. Varga<br>Paul Hastings, LLP<br>515 South Flower Street, 25th Floor<br>Los Angeles, CA 90071<br>*Attorneys for Amicus Curiae Independent Energy Producers Association* |

| |
|---|
| Douglas Mo<br>Prentiss Willson, Jr.<br>Sutherland, Asbill & Brennan LLP<br>500 Capitol Mall, 19th Floor<br>Sacramento, CA 95814<br>*Attorneys for Amicus Curiae Broadband Tax Institute* |
| Eric S. Tresh<br>Sutherland, Asbill & Brennan LLP<br>999 Peachtree NE, Suite 2300<br>Atlanta, Georgia 30309<br>*Attorneys for Amicus Curiae Broadband Tax Institute* |
| Richard N. Wiley<br>775 E. Blithedale Ave., Ste. 369<br>Mill Valley, CA 94941<br>*Attorney for Amicus Curiae Wirelessco., L.P.* |
| Richard R. Patch<br>Jeffrey Sinsheimer<br>Charmaine G. Yu<br>Coblenz, Patch, Duffy & Bass LLP<br>One Ferry Building, Suite 200<br>San Francisco, CA 94111-4213<br>*Attorneys for Amicus Curiae California Cable and Telecommunications Association* |
| Cris K. O'Neall<br>Cahill, Davis & O'Neall, LLP<br>550 S. Hope Street, Suite 1650<br>Los Angeles, California 90071<br>*Attorneys for Amici Curiae California Taxpayers Association, California Manufacturers & Technology Association and Silicon Valley Leadership Group* |
| Wm. Gregory Turner<br>Council On State Taxation<br>1415 L Street, Suite 1200<br>Sacramento, CA 95814<br>*Attorney for Amicus Curiae Council on State Taxation* |

| |
|---|
| Steve Mitra<br>County of Santa Clara<br>70 West Hedding St., 9th Floor, East Wing<br>San Jose, CA 95110<br>*Attorney for Amici Curiae California State Association of Counties and California Assessors' Association* |
| Edward G. Summers<br>San Diego Middle Class Taxpayers Association<br>3737 Camino Del Rio South, Suite 203<br>San Diego, CA 92108-4007<br>*Attorney for Amicus Curiae San Diego Middle Class Taxpayers Association* |
| Michael Wall<br>Alex Jackson<br>Natural Resources Defense Council<br>111 Sutter St., 20th Fl.<br>San Francisco, CA 94110<br>*Attorneys for Amicus Curiae Natural Resources Defense Council* |
| John F. Krattli<br>Albert Ramseyer<br>Los Angeles County Assessor<br>500 West Temple Street, Room 648<br>Los Angeles, CA 90012-2713<br>*Attorneys for Amicus Curiae John R. Noguez, Los Angeles County Assessor* |
| John Stump<br>Sierra Club<br>85 Second St., 2nd Floor<br>San Francisco, CA 94105<br>*Attorney for Amicus Curiae Sierra Club* |
| Ann Hancock<br>Climate Protection Campaign<br>P.O. Box 3785<br>Santa Rosa, CA 95402 |

5. I am a resident of or employed in the county where the mailing occurred. The document was mailed from Mesa, Arizona.

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

Date: July 24, 2012

Kim Simonis
Printed Name

Kim Simonis
Signature

# COMMISSION DECISION

## APPLICATION FOR CERTIFICATION

# *ELK HILLS*
## *POWER PROJECT*

**Docket No. 99-AFC-1**

Gray Davis, *Governor*

DECEMBER 2000

CALIFORNIA
ENERGY
COMMISSION

P 800-00-013

**_CALIFORNIA ENERGY COMMISSION_**

| Committee | Hearing Office |
| --- | --- |
| Wiilliam J. Keese, Chairman | Stanley Valkosky, Chief Hearing Offi |
| Robert A. Laurie, Commissioner | Major Williams, Jr., Hearing |
| Michal C. Moore, Commissioner | |
| Robert Pernell, Commissioner | |
| Arthur H. Rosenfeld, Ph.D., Commissioner | |

**STATE OF CALIFORNIA**

**Energy Resources**
**Conservation and Development Commission**

| | | |
|---|---|---|
| **In the Matter of:** | ) | **Docket No. 99-AFC-1** |
| | ) | |
| **Application for Certification for the Elk Hills Cogeneration Power Project** | ) | **COMMISSION ADOPTION ORDER** |

This Commission Order adopts the Commission Decision on the Elk Hills Cogeneration Power Project. It incorporates the Presiding Member s Proposed Decision (PMPD) in the above-captioned matter and the Committee Errata (___Date_______) thereto. The Commission Decision is based upon the evidentiary record of these proceedings (Docket No. 99-AFC-1) and considers the comments received at the ---------------------- business meeting. The text of the attached Commission Decision contains a summary of the proceedings, the evidence presented, and the rationale for the findings reached and Conditions imposed.

This ORDER adopts by reference the text, Conditions of Certification, Compliance Verifications, and Appendices contained in the Commission Decision. It also adopts specific requirements contained in the PMPD which ensure that the proposed facility will be designed, sited, and operated in a manner to protect environmental quality, to assure public health and safety, and to operate in a safe and reliable manner.

## FINDINGS

The Commission hereby adopts the following findings in addition to those contained in the accompanying text:

1. The Elk Hills Power Project is a merchant power plant whose capital costs will not be borne by the State s electricity ratepayers.

2. The Conditions of Certification contained in the accompanying text, if implemented by the Applicant, ensure that the project will be designed, sited, and operated in conformity with applicable local, regional, state, and federal laws, ordinances, regulations, and standards, including applicable public health and safety standards, and air and water quality standards.

3. Implementation of the Conditions of Certification contained in the accompanying text will ensure protection of environmental quality and assure reasonably safe and reliable operation of the facility. The Conditions of Certification also assure that the project will neither result in, nor contribute substantially to, any significant direct, indirect, or cumulative adverse environmental impacts.

4. Existing governmental land use restrictions are sufficient to adequately control population density in the area surrounding the facility and may be reasonably expected to ensure public health and safety.

5. The evidence of record establishes that no feasible alternatives to the project, as described during these proceedings, exist.

6. The evidence of the record does not establish the existence of any environmentally superior alternative site.

7. The PMPD contains measures to ensure that the planned, temporary, or unexpected closure of the project will occur in conformance with applicable laws, ordinances, regulations, and standards.

8. The proceedings leading to this Decision have been conducted in conformity with the applicable provisions of Commission regulations governing the consideration of an Application for Certification and thereby meet the requirements of Public Resources Code, sections 21000 et. seq., and 25500 et. seq..

## ORDER

Therefore, the Commission ORDERS the following:

1. The Application for Certification of the Elk Hills Power Project as described in this Decision is hereby approved and a certificate to construct and operate the project is hereby granted.

2. The approval of the Application for Certification is subject to the timely performance of the Conditions of Certification and Compliance Verifications enumerated in the accompanying text and Appendices. The Conditions and Compliance Verifications are integrated with this Decision and are not severable therefrom. While Applicant may delegate the performance of a Condition or Verification, the duty to ensure adequate performance of a Condition or Verification may not be delegated.

3. For purposes of reconsideration pursuant to Public Resources Code section 25530, this Decision is deemed adopted when filed with the Commission s Docket Unit.

4. For purposes of judicial review pursuant to Public Resources Code section 25531, this Decision is final thirty (30) days after its filing in the absence of the filing of a petition for reconsideration or, if a petition for reconsideration is filed within thirty (30) days, upon the adoption and filing of an Order upon reconsideration with the Commission s Docket Unit.

5. The Commission hereby adopts the Conditions of Certification, Compliance Verifications, and associated dispute resolution procedures as part of this Decision in order to implement the compliance monitoring program required by Public Resources Code section 25532. All conditions in this Decision take effect immediately upon adoption and apply to all construction and site preparation activities including, but not limited to, ground disturbance, site preparation, and permanent structure construction.

6. The Executive Director of the Commission shall transmit a copy of this Decision and appropriate accompanying documents as provided by Public Resources Code section 25537 and California Code of Regulations, title 20, section 1768.

**Dated:** ___________

**ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION**

WILLIAM J. KEESE
Chairman

ROBERT A. LAURIE
Commissioner

MICHAL C. MOORE
Commissioner

ROBERT PERNELL
Commissioner

ARTHUR H. ROSENFELD
Commissioner

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Staff also points out that Midway-Sunset s AFC was not deemed data adequate until March 8, 2000, when many evidentiary hearings in Elk Hills had already concluded. (Staff Reply Brief on Phase IIII issues, p. 2.) Staff has requested that Midway-Sunset submit a cumulative analysis that includes Midway-Sunset, La Paloma, Sunrise, and Elk Hills. (Ex. 19D, Part III, p. 24.) We are thus persuaded to defer to Staff s original judgment not to request the analysis from Elk Hills in the first instance. We therefore reject CURE s contention that the cumulative impact analysis is flawed. The existing cumulative analysis considers all projects within a sufficient distance for impact assessment purposes.

Similarly, CURE s contention that meteorological data relied on by Applicant and Staff was flawed is without merit. Applicant points out that the reliance on old data was corrected. (Applicant s Reply Brief on Phase III issues, p. 1.) The new data confirmed the previous finding that the project would not cause any air quality standard violations and would comply with all applicable air quality LORS. *(Ibid.)*

**FINDINGS AND CONCLUSIONS**

Based upon the weight of the evidence of record, we find and conclude as follows:

1. The Elk Hills Power Project is located in the San Joaquin Valley Air Basin, within the jurisdiction of the San Joaquin Valley Unified Air Pollution Control District (SJVAPCD).

2. The project area is in unclassified/attainment status for applicable federal CO and $NO_2$ air quality standards, in attainment for the state s CO, $NO_2$, $SO_2$, $SO_4$, and lead standards, and in attainment for federal $SO_2$ standard. It is designated as non-attainment for both state and federal ozone and $PM_{10}$ standards.

3. Construction and operation of the Elk Hills Power Project will result in emission of criteria air pollutants.

4. Operation of the project will result in emissions of $NO_x$, $SO_2$, $PM_{10}$, and VOC, which would, if not mitigated, contribute to violations of air quality standards.

5. The Elk Hills Power Project will use Best Available Control Technology (BACT) as determined by the San Joaquin Valley Unified Air Pollution Control District to control emissions of $NO_x$, CO, $SO_2$, $PM_{10}$, and VOC.

6. To minimize $NO_x$, CO and VOC emissions during the combustion process, the CTG will be equipped with the latest dry low-$NO_x$ combustor design; the HRSG will employ SCR to reduce NOx emissions, and an oxidizing catalyst to reduce CO and VOC emissions.

7. SJVAPCD released its Final Determination of Compliance (FDOC) for the Elk Hills project on March 30, 2000. The conditions contained in the FDOC are incorporated into the Conditions of Certification below.

8. A representative of the SJVUAPCD has certified that complete emissions offsets for the project have been identified and obtained by the Applicant.

9. BACT for the project s $NO_x$ emissions is 2.5 ppm @ 15% O2 averaged over one hour, to obtain which Applicant will install DLN-SCR rather than SCONOx.

10. SCONOx for the proposed project is approximately three times the cost per turbine as compared to SCR-oxidation catalyst.

11. Applicant has obtained, by direct transfers or legally enforceable option contracts, Emission Reduction Credits (ERCs) sufficient to fully offset the project s increased emissions of $NO_x$, $SO_2$, VOC, and $PM_{10}$, due to project operation, on an annual and a daily basis.

12. To offset $PM_{10}$ emissions during construction, Applicant shall install oxidizing soot filters on large construction equipment under the conditions set forth below in Condition **AQ-C2**.

13. The Elk Hills Power Project, with the implementation of the measures contained in the Conditions of Certification below, will not, either alone or in combination with other identified projects in the area, cause or contribute to any new or existing violations of applicable ambient air quality standards.

14. With the implementation of the Conditions of Certification specified below, the Elk Hills Power Project will be constructed and operated in compliance with all applicable laws, ordinances, regulations, and standards identified in the pertinent portion of Appendix A of this Decision.

We therefore conclude that with the implementation of the Conditions of Certification below, the Elk Hills Power Project will not create any significant direct, indirect, or cumulative adverse air quality impacts; and will conform with all applicable LORS relating to air quality as set forth in the pertinent portions of Appendix A of this Decision.

## CONDITIONS OF CERTIFICATION

**AQ-C1** Prior to breaking ground at the project site, the project owner shall prepare a Construction Fugitive Dust Mitigation Plan (CFDMP), which specifically:

- identifies fugitive dust mitigation measures that will be employed for the construction of the Elk Hills Power Project and related facilities; and
- identifies measures to limit fugitive dust emissions from construction of the project site and linear facilities. Measures that should be addressed include the following:

  the identification of the employee parking area(s) and surface of the parking area(s);
  the frequency of watering of unpaved roads and disturbed areas;
- the application of chemical dust suppressants;
- the use of gravel in high traffic areas;
- the use of paved access aprons;
- the use of posted speed limit signs;
- the use of wheel washing areas prior to large trucks leaving the project site; and,
- the methods that will be used to clean tracked-out mud and dirt from the project site onto public roads.

**Verification:** At least sixty (60) days prior to breaking ground at the project site, the project owner shall provide the CPM with a copy of the Construction Fugitive Dust Mitigation Plan for approval.

**AQ-C2** The project owner shall do all of the following:

1. Ensure that all heavy earthmoving equipment has been properly maintained, including, but not limited to:
   - bulldozers,
   - backhoes,
   - compactors,
   - cranes
   - dump trucks
   - loaders,
   - motor graders

- trenchers, and
- other heavy duty construction related trucks.

2. Engines shall be:

   (a) tuned to the engine manufacturer s specifications;

   (b) provided with ignition retard equipment where feasible, to provide additional NOx emission reductions during construction. Feasibility shall be determined by an independent California Licensed Mechanical Engineer under the identical circumstances presented below.

3. Install oxidizing soot filters on all suitable construction equipment used either on the power plant construction site or on associated linear construction sites. Suitability is to be determined by an independent California Licensed Mechanical Engineer who will stamp and submit for approval an initial and all subsequent Suitability Reports as necessary containing at a minimum the following:

4. File an Initial Suitability Report. The initial suitability report shall be submitted to the CPM for approval sixty (60) days prior to breaking ground on the project site. It shall contain:

   - A list of all fuel burning, construction related equipment used;
   - a determination of the suitability of each piece of equipment to work appropriately with an oxidizing soot filter;
   - if a piece of equipment is determined to be suitable, a statement by the independent California Licensed Mechanical Engineer that the oxidizing soot filter has been installed and is functioning properly; and
   - if a piece of equipment is determined to be unsuitable, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination.

5. File a Subsequent Suitability Reports as follows:
   - If a piece of construction related equipment is subsequently determined to be unsuitable for an oxidizing soot filter after such installation has occurred, the filter may be removed immediately.
   - In that event, notification must be sent to the CPM for approval containing an explanation for the change in suitability within ten (10) days.

- Changes in suitability are restricted to three explanations, which must be identified in any subsequent suitability report, as shown below:
- The oxidizing soot filter is reducing normal availability of the construction equipment due to increased downtime, and/or power output due to increased backpressure by 20% or more.
- The oxidizing soot filter is causing or reasonably expected to cause significant damage to the construction equipment engine.
- The oxidizing soot filter is causing or reasonably expected to cause a significant risk to nearby workers or the public.

**Verification:** The project owner shall submit to the CPM, via the Monthly Compliance Report, documentation, which demonstrates that the contractor s heavy earthmoving equipment is properly maintained and the engines are tuned to the manufacturer s specifications. The project owner shall maintain all records on the site for six months following the start of commercial operation. The project owner will submit to the CPM for approval, the initial suitability report stamped by an independent California Licensed Mechanical Engineer, sixty (60) days prior to breaking ground on the project site. The project owner will submit to the CPM for approval, subsequent suitability reports as required, stamped by an independent California Licensed Mechanical Engineer no later than ten (10) working day following a change in the suitability status of any construction equipment.

**Conditions of Certification AQ-1 through AQ-44** apply to the following equipment:

**SJVUAPCD Permit No. S-3523-1-0- GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDIATION CATALYST, AND STEAM TURBINE S-3532-2 (503 MW TOTAL NOMINAL RATING),**

**SJVUAPCD Permit No. S-3523-2-0- GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDIATION CATALYST, AND STEAM TURBINE S-3532-2 (503 MW TOTAL NOMINAL RATING),**

**AQ-1** No air contaminant shall be released into the atmosphere, which causes a public nuisance. [District Rule 4102]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, California Air Resources Board (CARB) and the Commission.

**AQ-2** The project owner shall submit selective catalytic reduction, oxidation catalyst, and continuous emission monitor design details to the District at least 30 days prior to the construction of permanent foundations. [District Rule 2201]

**Verification:** The project owner shall provide copies of the drawings of the catalyst system chosen and the continuous emission monitor design detail to the CPM and the District at least thirty (30) days prior to the construction of permanent foundations.

**AQ-3** Combustion turbine generator (CTG) and electric generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents shall no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-4** The CTG shall be equipped with continuously recording fuel gas flowmeter. [District Rule 2201]

**Verification:** The information above shall be included in the quarterly reports of Condition **AQ-35.**

**AQ-5** CTG exhaust shall be equipped with continuously recording emissions monitor for NOx (before and after the SCR unit), CO, and O2 dedicated to this unit. Continuous emission monitors shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. If relative accuracy of CEM(s) cannot be certified during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained during source testing to determine compliance with emission limits in Conditions **AQ-13, 16, 17 and 18**. [District Rule 2201]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-6** Ammonia injection grid shall be equipped with operational ammonia flowmeter and injection pressure indicator. [District Rule 2201]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-7** Exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods. [District Rule 1081]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-8** Heat recovery steam generator design shall provide space for additional selective catalytic reduction catalyst and oxidizing catalyst if required to meet NOx and CO emission limits. [District Rule 2201]

**<u>Verification</u>:** Please refer to Condition **AQ-2**.

**AQ-9** The project owner shall monitor and record exhaust gas temperature at the selective catalytic reduction and oxidation catalyst inlets. [District Rule 2201]

**<u>Verification</u>:** The project owner shall record the exhaust gas and selective catalytic reduction temperatures in the daily logs.

**AQ-10** CTG shall be fired on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry-scf of natural gas. [District Rule 2201]

**<u>Verification</u>:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-11** Startup is defined as the period beginning with initial turbine firing until the unit meets the lb/hr and ppmv emission limits in Condition **AQ-15**. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown duration shall not exceed the following:

- two hours for a regular startup,
- four hours for an extended startup,
- and one hour for a shutdown, per occurrence. [District Rule 2201 and 4001]

**<u>Verification</u>:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-12** Ammonia shall be injected when the SCR catalyst temperature exceeds 500 degrees F. The project owner shall monitor and record catalyst temperature during periods of startup. [District Rules 2201]

**<u>Verification</u>:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-13** During startup or shutdown of any gas turbine engine(s), combined emissions from both gas turbine engines (s-3523-1-0 and —2-0) heat recovery steam generator exhausts shall not exceed any of the following limits in any one hour:

- $NO_x$ (as $NO_2$) 76 lbs
- CO 38 lbs

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-14** By two hours after initial turbine firing, CTG exhaust emissions shall not exceed any of the following: $NO_x$ (as $NO_2$) 12.2 ppmv @ 15% $O^2$ and CO 25 ppmv @ 15% $O^2$. [District Rule 4703]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-15** Emission rates from each CTG, except during startup or shutdown, shall not exceed any of the following emission limits:

- $PM_{10}$ 18 lbs/hr
- $SO_2$ 3.6 lbs/hr
- $NO_2$ 15.8 lbs/hr and 2.5 ppmvd @ 15% $O^2$ averaged over 1-hr
- VOC 4.0 lbs/hr and 2.0 ppmvd @ 15% $O^2$ averaged over 3-hr
- CO 12.5 lbs/hr and 4 ppmvd @ 15% $O^2$ averaged over 3-hr
- Ammonia 10 ppmvd @ 15% $O^2$ averaged over 24-hr [District Rule 2201, 4001 and 4703]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-16** Emission rates from each CTG, on days when a startup or shutdown occurs, shall not exceed any of the following:

- $PM_{10}$ 432 lbs/day
- $SO_2$ 86.4 lbs/day
- $NO_2$ 418.5 lbs/day
- VOC 96.0 lbs/day
- CO 326.7 lbs/day [District Rule 2201]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-17** Emission rates from both CTGs (S-3523-1 and -2), on days when a startup or shutdown occurs for either or both turbines, shall not exceed any of the following:

- $PM_{10}$ 864.0 lb/day
- $SO_2$ 172.8 lb/day
- $NO_2$ 817.8 lb/day
- VOC 192.0 lb/day
- CO 640.4 lb/day. [District Rule 2201]

The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-18** Annual emissions from both CTGs calculated on a twelve (12) consecutive month rolling basis shall not exceed any of the following: PM10 -

315,360 lb/year, $SO_x$ (as $SO_2$) - 57,468 lb/year, $NO_x$ (as $NO_2$) - 285,042 lb/year, VOC - 64,478 lb/year, and CO - 223,040 lb/year. [District Rule 2201]

<u>**Verification**</u>: The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-19** Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a three-hour rolling average will commence on the hour. The three-hour average will be compiled from the three most recent one-hour periods. Each one-hour period in a twenty-four-hour average for ammonia slip will commence on the hour. The twenty-four-hour average will be calculated starting and ending at twelve-midnight. [District Rule 2201]

<u>**Verification**</u>: The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-20** Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each calendar month in twelve-consecutive-month rolling emissions will commence at the beginning of the first day of the month. The twelve-consecutive-month rolling emissions total to determine compliance with annual emissions will be compiled from the twelve (12) most recent calendar months. [District Rule 2201]

<u>**Verification**</u>: The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-21** Prior to or upon startup of S-3523-1-0, -2-0, & 3-0, emission offsets shall be surrendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1, $PM_{10}$ - Q1: 78,596 lb, Q2: 79,470 lb, Q3: 80,343 lb, and Q4: 80,343 lb; SOx (as $SO_2$) - Q1: 14,170 lb, Q2: 14,328 lb , Q3: 14,485 lb, and Q4: 14,485 lb; NOx (as $NO_2$) - Q1: 65,353 lb, Q2: 66,079 lb, Q3: 66,805 lb, and Q4: 66,805 lb; and VOC - Q1: 10,967 lb, Q2: 11,089 lb, Q3: 11,211 lb, and Q4: 11,211 lb. [District Rule 2201]

<u>**Verification**</u>: The owner/operator shall submit copies of ERC surrendered to the SJVUAPCD in the totals shown to the CPM prior to or upon startup of the CTGs or cooling tower.

**AQ-22** $NO_x$ and VOC emission reductions that occurred from April through November may be used to offset increases in $NO_x$ and VOC respectively during any period of the year. [District Rule 2201]

<u>**Verification**</u>: The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-21.**

**AQ-23** $NO_x$ ERCs may be used to offset $PM_{10}$ emission increases at a ratio of 2.42 lb $NO_x$: 1 lb $PM_{10}$ for reductions occurring within fifteen (15) miles of this facility, and at 2.72 lb $NO_x$: 1 lb $PM_{10}$ for reductions occurring greater than fifteen (15) miles from this facility. [District Rule 2201]

**Verification:** The project owner shall provide records of the ERCs as part of Condition **AQ-21.**

**AQ-24** At least thirty (30) days prior to the construction of permanent foundations, the project owner shall provide the District with:

- written documentation that all necessary offsets have been acquired or that
- binding contracts to secure such offsets have been entered into. [District Rule 2201]

**Verification:** The project owner shall provide ERC records as part of Condition **AQ-21.**

**AQ-25** Compliance with ammonia slip limit shall be demonstrated by using the following calculation procedure: ammonia slip ppmv @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000 / b) x d, where a = ammonia injection rate(lb/hr)/17(lb/lb. mol), b = dry exhaust gas flow rate (lb/hr)/(29(lb/lb. mol), c = change in measured $NO_x$ concentration ppmv at 15% O2 across catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the project owner may utilize a continuous in-stack ammonia monitor, acceptable to the District, to monitor compliance. At least 60 days prior to using a NH3 CEM, the project owner must submit a monitoring plan for District review and approval [District Rule 4102]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-26** Compliance with the short term emission limits (lb/hr and ppmv @ 15% O2) shall be demonstrated within 60 days of initial operation of each gas turbine engine and annually thereafter. On site sampling of exhaust gasses at full load conditions by a qualified independent source test firm, in full view of District witnesses, as follows:

- $NO_x$: ppmvd @ 15% O2 and lb/hr;
- CO: ppmvd @ 15% $O_2$ and lb/hr;
- VOC: ppmvd @ 15% $O_2$ and lb/hr;
- $PM_{10}$: lb/hr; and
- ammonia: ppmvd @ 15% $O_2$.

Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rule 1081]

**Verification:** The project owner shall provide records of compliance as part of Condition **AQ-29.**

**AQ-27** Compliance with the startup $NO_x$, CO, and VOC mass emission limits shall be demonstrated for one of the CTGs (S-3523-1, or -2) upon initial operation and at least every seven years thereafter by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081]

**Verification:** The project owner shall provide records of compliance as part of Condition **AQ-29.**

**AQ-28** Compliance with natural gas sulfur content limit shall be demonstrated within sixty (60) days of operation of each gas turbine engine and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-29** The District must be notified thirty (30) days prior to any compliance source test, and a source test plan must be submitted for approval fifteen (15) days prior to testing. Official test results and field data collected by source tests required by conditions on this permit shall be submitted to the District within sixty (60) days of testing. [District Rule 1081]

**Verification:** The project owner shall notify the CPM and the District thirty (30) days prior to any compliance source test. The project owner shall provide a source test plan to the CPM and District for the CPM and District approval fifteen (15) days prior to testing. The results and field data collected by the source tests shall be submitted to the CPM and the District within 60 days of testing.

**AQ-30** Source test plans for initial and seven-year source tests shall include:

- a method for measuring the VOC/CO surrogate relationship that will be used to demonstrate compliance with VOC lb/hr, lb/day; and
- lb/twelve month rolling emission limits. [District Rule 2201]

**Verification:** The project owner shall provide a source test plan to the CPM and District for the CPM and District approval fifteen (15) days prior to testing. The results and field data collected by the source tests shall be submitted to the CPM and the District within sixty (60) days of testing.

**AQ-31** The following test methods shall be used:

- $PM_{10}$: EPA method 5 (front half and back half),
- $NO_x$: EPA Method 7E or 20,
- CO: EPA method 10 or 10B, O2: EPA Method 3, 3A, or 20,

- VOC: EPA method 18 or 25,
- ammonia: BAAQMD ST-1B, and
- fuel gas sulfur content: ASTM D3246.

EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

**Verification:** The project owner shall provide records of compliance as part of Condition **AQ-29.**

**AQ-32** The project owner shall notify District of the:

- date of initiation of construction no later than 30 days after such date;
- date of anticipated startup not more than 60 days nor less than 30 days prior to such date; and
- date of actual startup within fifteen (15) days after such date. [District Rule 4001]

**Verification:** Within thirty (30) days after such event, the project owner shall notify the CPM and the District of the date of initiation of construction.

Not more than sixty (60) days or less than thirty (30) days prior to such event, the CPM and the District shall be notified of the date of anticipated startup.

The CPM and the District shall be notified within fifteen (15) days after actual startup .

**AQ-33** The project owner shall maintain hourly records of $NO_x$, CO, and ammonia emission concentrations (ppmv @ 15% $O_2$), and hourly, daily, and twelve month rolling average records of NOx and CO emissions. Compliance with the hourly, daily, and twelve-month rolling average VOC emission limits shall be demonstrated by the CO CEM data and the VOC/CO relationship determined by annual CO and VOC source tests. [District Rule 2201]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-34** The project owner shall maintain records of $SO_x$ lb/hr, lb/day, and lb/twelve month rolling average emission. $SO_x$ emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-35** The project owner shall maintain the following records for the CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 & 4703]

**Verification:** The project owner shall compile required data and submit the information to the CPM in quarterly reports submitted no later than thirty (30) days after the end of each calendar quarter.

**AQ-36** The project owner shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 & 4703]

**Verification:** The project owner shall provide records of compliance as part of the quarterly reports of Condition **AQ-35.**

**AQ-37** All records required to be maintained by this permit shall be maintained for a period of five (5) years and shall be made readily available for District inspection upon request. [District Rule 2201]

**Verification:** The project owner shall make records available for inspection by representatives of the District, CARB and the Commission upon request.

**AQ-38** Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, and paragraphs 5.0 through 5.3. 3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

**Verification:** The project owner shall compile the required data in the formats discussed above and submit the results as part of the quarterly reports specified in Condition AQ-35.

**AQ-39** Not later than one (1) hour after its detection, the project owner shall notify the District of any breakdown condition, unless the owner or operator demonstrates to the Districts satisfaction that the longer reporting period was necessary. [District Rule 1100]

**Verification:** The project owner shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM as part of the quarterly reports of Condition **AQ-35**.

**AQ-40** The District shall be notified in writing within ten (10) days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

**Verification:** The project owner shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM as part of the quarterly reports of Condition **AQ-35**.

**AQ-41** Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

**<u>Verification</u>:** The project owner shall submit the continuous emission monitor audit results with the quarterly reports required of Condition **AQ-43**.

**AQ-42** The project owner shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

**<u>Verification</u>:** The project owner shall submit the continuous emission monitor results with the quarterly reports of Condition **AQ-43**.

**AQ-43** Within thirty (30) days of the end of the quarter, for each calendar quarter, the project owner shall submit a written report to the APCO that includes:

- time intervals,
- data and magnitude of excess emissions,
- nature and cause of excess (if known),
- corrective actions taken and preventive measures adopted.

Averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

**<u>Verification</u>:** The project owner shall compile the required data and submit the quarterly reports to the CPM and the APCO within thirty (30) days of the end of the quarter.

**AQ-44** The project owner shall submit an application to comply with Rule 2540 - Acid Rain Program twenty four (24) months before the unit commences operation. [District Rule 2540]

**<u>Verification</u>:** The project owner shall file their application with the District at least twenty four (24) months prior to the commencement of operation of any of the combustion turbine generators.

Conditions of Certification **AQ-45** through **AQ-52** apply to the following equipment:

**FORCED DRAFT COOLING TOWER WITH 6 CELLS AND HIGH EFFICIENCY DRIFT ELIMINATOR S-3523-3-0:**

**AQ-45** No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-46** At least thirty (30) days prior to commencement of construction, the project owner shall submit to the District:

- drift eliminator design details; and
- vendor specific emission justification for the correction factor to be used to correlate blowdown TDS to drift TDS and the amount of drift that stays suspended in the atmosphere utilizing the equation in Condition **AQ-51**. [District Rule 2201]

**Verification:** Thirty (30) days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the District and the CPM.

**AQ-47** The project owner shall submit to the District cooling tower design details (including the cooling tower type and materials of construction) at least thirty (30) days prior to commencement of construction, and, at least ninety (90) days before the tower is to be operated. [District Rule 7012]

**Verification:** Thirty (30) days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the District and the CPM.

**AQ-48** No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-49** Drift eliminator drift rate shall not exceed 0.0006%. [District Rule 2201]

**Verification:** The project owner shall submit documentation from the selected cooling tower vendor that verifies the drift efficiency to the CPM thirty (30) days prior to commencement of construction of the cooling towers.

**AQ-50** $PM_{10}$ emission rate shall not exceed 9.3 lb/day. [District Rule 2201]

**Verification:** Please refer to Condition **AQ-51**.

**AQ-51** Compliance with the $PM_{10}$ daily emission limit shall demonstrated as follows: $PM_{10}$ lb/day = circulating water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate * correction factor. [District Rule 2201]

**Verification:** The project owner shall compile the required daily $PM_{10}$ emissions data and maintain the data for a period of five (5) years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-52** Compliance with $PM_{10}$ emission limit shall be determined by circulating water sample analysis by independent laboratory within 90 days of initial operation and weekly thereafter. [District Rule 1081]

**Verification:** The project owner shall compile the required daily PM10 emissions data and maintain the data for a period of five (5) years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

Conditions of Certification **AQ-53** through **AQ-62** apply to the following equipment:

**SAMPLE EQUIPMENT DESCRIPTION: 125 HP PERKINS/DETROIT DIESEL MODEL PDFP-06YR DIESEL-FIRED IC ENGINE DRIVING EMERGENCY FIRE WATER PUMP S-3523-4-0:**

**AQ-53** No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-54** No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-55** The engine shall be equipped with a turbocharger and intercooler/aftercooler. [District Rule 2201]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-56** The engine shall be equipped with an operational non-resettable hour meter. [District Rule 2201]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-57** The engine shall be equipped with a positive crankcase ventilation (PCV) system or a crankcase emissions control device of at least 90% control efficiency unless UL certification would be voided. [District Rule 2201]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-58** $NO_x$ emissions shall not exceed 7.2 g/hp-hr. [District Rule 2201].

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-59** The sulfur content of the diesel fuel used shall not exceed 0.05% by weight. [District Rule 2201]

**Verification:** Please refer to Condition **AQ-62**.

**AQ-60** Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

**AQ-61** The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District Rules 2201 and 4701]

**Verification:** The project owner shall compile records of hours of operation of any of the IC engines and include those records as part of the quarterly reports submitted to the CPM under Condition **AQ-35**.

**AQ-62** The project owner shall maintain records of hours of non-emergency operation and of the sulfur content of the diesel fuel used. Such records shall be made available for District inspection upon request for a period of five (5) years. [District Rules 2201 and 4701]

**Verification:** The project owner shall compile records of hours of operation of the IC engines and of the diesel fuel purchased that includes the sulfur content, and maintain the data for a period of five years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

U.S. Energy Information Administration

# International Energy Outlook 2011

**Release Date:** September 19, 2011 |
Report Number: DOE/EIA-0484(2011)

## Electricity

### Overview

Figure 72. Growth in world electricity generation and total delivered energy consumption, 1990-2035
(index, 1990=1)

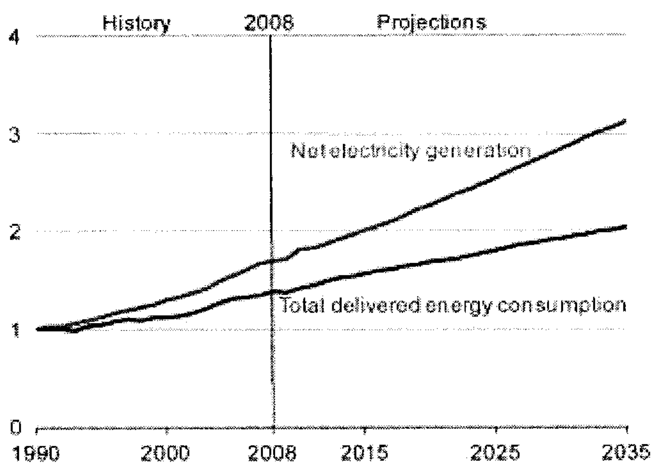



figure data

In the *IEO2011* Reference case, electricity supplies an increasing share of the world's total energy demand, and electricity use grows more rapidly than consumption of liquid fuels, natural gas, or coal in all end-use sectors except transportation. From 1990 to 2008, growth in net electricity generation outpaced the growth in delivered energy consumption (3.0 percent per year and 1.8 percent per year, respectively). World demand for electricity increases by 2.3 percent per year from 2008 to 2035 and continues to outpace growth in total energy use throughout the projection period (Figure 72).

World net electricity generation increases by 84 percent in the Reference case, from 19.1 trillion kilowatthours in 2008 to 25.5 trillion kilowatthours in 2020 and 35.2 trillion kilowatthours in 2035 (Table 11). Although the 2008-2009 global economic recession slowed the rate of growth in electricity use in 2008 and resulted in negligible change in electricity use in 2009, worldwide electricity demand increased by an estimated 5.4 percent in 2010, with non-OECD electricity demand alone increasing by an estimated 9.5 percent.

In general, projected growth in OECD countries, where electricity markets are well established and consumption patterns are mature, is slower than in non-OECD countries, where a large amount of demand goes unmet at present. The electrification of historically off-grid areas plays a strong role in projected growth trends. The International Energy Agency estimates that 21 percent of the world's population did not have access to electricity in 2009—a total of about 1.4 billion people [207]. Regionally, sub-Saharan Africa is worst off: more than 69 percent of the population currently remains without access to power. With strong economic growth and targeted government programs, however, electrification can occur quickly. In

Vietnam, for example, the government's rural electrification program increased access to power from 51 percent of rural households in 1996 to 95 percent at the end of 2008 [208].

Figure 73. OECD and non-OECD net electricity generation, 1990-2035
(trillion kilowatthours)

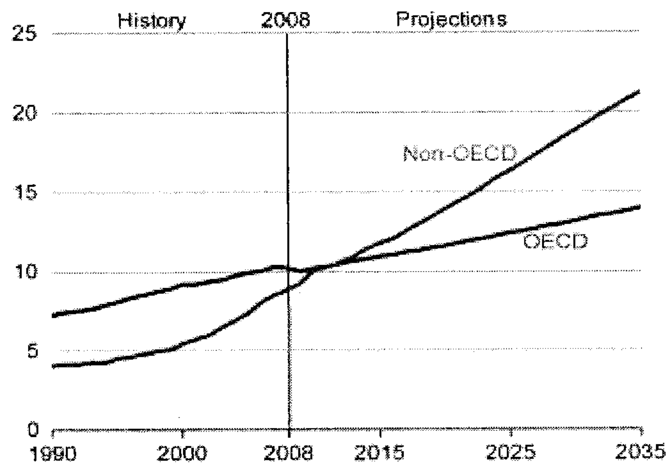



figure data

Non-OECD nations consumed 47 percent of the world's total electricity supply in 2008, and their share of world consumption is poised to increase over the projection period. In 2035, non-OECD nations account for 60 percent of world electricity use, while the OECD share declines to 40 percent (Figure 73). Total net electricity generation in non-OECD countries increases by an average of 3.3 percent per year in the Reference case, led by annual increases averaging 4.0 percent in non-OECD Asia (including China and India) from 2008 to 2035 (Figure 74). In contrast, total net generation in the OECD nations grows by an average of only 1.2 percent per year from 2008 to 2035.

Figure 74. Non-OECD net electricity generation by region, 1990-2035
(trillion kilowatthours)

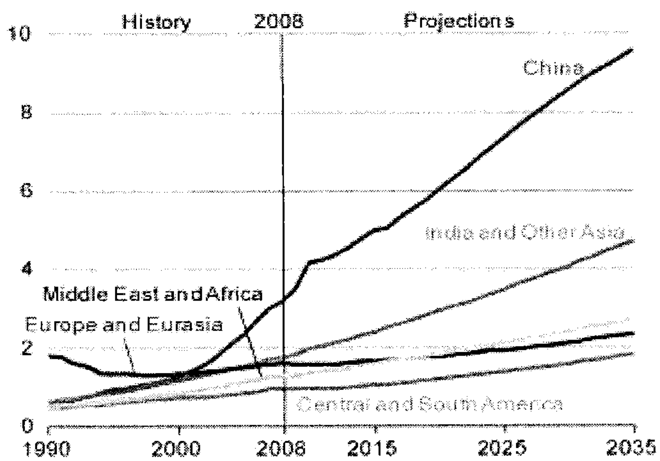



figure data

The outlook for total electricity generation is largely the same as projected in last year's report. However, the projected mix of generation by fuel in the *IEO2011* Reference case has changed. The largest difference between the two outlooks is for natural-gas-fired generation—which is 22 percent higher in this year's outlook in 2035. The more optimistic outlook for generation from natural gas-fired power plants is a result of a reassessment of available gas supplies. This year's IEO includes an upward revision in potential gas supplies, largely because of increases in unconventional supplies of natural gas in the United States and other parts of the world. The increase in the natural gas share of generation to a large extent displaces coal-fired generation, which is 14 percent lower than in last year's report. In addition, projected nuclear power generation is 9 percent higher, and generation from renewable sources is 3 percent higher in 2035 than projected in *IEO2010*. The nuclear projection does not reflect consideration of policy responses to Japan's Fukushima Daiichi nuclear disaster, which are likely to reduce projected nuclear generation from both existing and new plants. Liquids-fired generation, in contrast, is 3 percent lower in this year's projection.

The *IEO2011* projections do not incorporate assumptions related to limiting or reducing greenhouse gas emissions, such as caps on carbon dioxide emissions levels or taxes on carbon dioxide emissions. However, the Reference case does incorporate current national energy policies, such as the European Union's "20-20-20" plan and its member states' nuclear policies; China's wind capacity targets; and India's National Solar Mission.[28]

## Electricity supply by energy source

The worldwide mix of primary fuels used to generate electricity has changed a great deal over the past four decades. Coal continues to be the fuel most widely used for electricity generation, although generation from nuclear power increased rapidly from the 1970s through the 1980s, and natural-gas-fired generation grew rapidly in the 1980s and 1990s. The use of oil for electricity generation has been declining since the mid-1970s, when oil prices rose sharply.

The high fossil fuel prices recorded between 2003 and 2008, combined with concerns about the environmental consequences of greenhouse gas emissions, have renewed interest in the development of alternatives to fossil fuels—specifically, nuclear power and renewable energy sources. In the *IEO2011* Reference case, long-term prospects continue to improve for generation from both nuclear and renewable energy sources—primarily supported by government incentives. Renewable energy sources are the fastest-growing sources of electricity generation in the *IEO2011* Reference case, with annual increases averaging 3.1 percent per year from 2008 to 2035. Natural gas is the second fastest-growing generation source, increasing by 2.6 percent per year, followed by nuclear power at 2.4 percent per year. Although coal-fired generation increases by an annual average of only 1.9 percent over the projection period, it remains the largest source of generation through 2035. However, the outlook for coal, in particular, could be altered substantially by any future national policies or international agreements aimed at reducing or limiting the growth of greenhouse gas emissions.

## Coal

Figure 75. World net electricity generation by fuel, 2008-2035
(trillion kilowatthours)

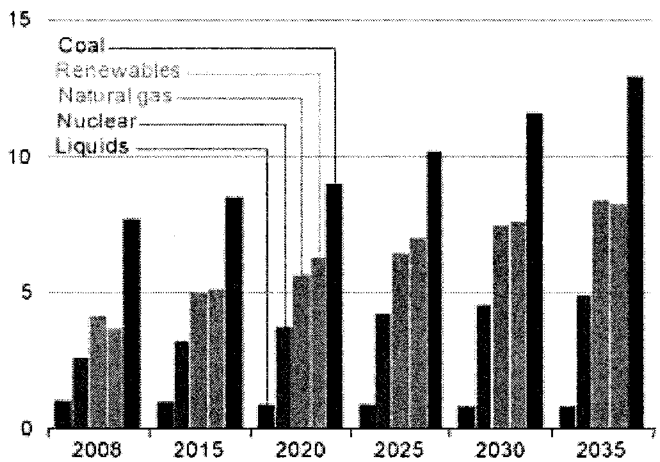



figure data

In the *IEO2011* Reference case, coal continues to fuel the largest share of worldwide electric power production by a wide margin (Figure 75). In 2008, coal-fired generation accounted for 40 percent of world electricity supply; in 2035, its share decreases to 37 percent, as renewables, natural gas, and nuclear power all are expected to advance strongly during the projection and displace the need for coal-fired-generation in many parts of the world. World net coal-fired generation grows by 67 percent, from 7.7 trillion kilowatthours in 2008 to 12.9 trillion kilowatthours in 2035.

The electric power sector offers some of the most cost-effective opportunities for reducing carbon dioxide emissions in many countries. Coal is both the world's most widely used source of energy for power generation and also the most carbon-intensive energy source. If a cost, either implicit or explicit, is applied to carbon dioxide emissions in the future, there are several alternative technologies with no emissions or relatively low levels of emissions that currently are commercially proven or under development and could be used to displace coal-fired generation.

### Natural gas

Over the 2008 to 2035 projection period, natural-gas-fired electricity generation increases by 2.6 percent per year. Generation from natural gas worldwide increases from 4.2 trillion kilowatthours in 2008 to 8.4 trillion kilowatthours in 2035, but the total amount of electricity generated from natural gas continues to be less than one-half the total for coal, even in 2035. Natural-gas-fired combined-cycle technology is an attractive choice for new power plants because of its fuel efficiency, operating flexibility (it can be brought online in minutes rather than the hours it takes for coal-fired and some other generating capacity), relatively short planning and construction times, relatively low emissions, and relatively low capital costs.

Prospects for natural gas have improved substantially relative to last year's outlook, in large part because of the revised expectations for unconventional sources of natural gas, especially shale gas,[29] both within the United States and globally. The additional resources will allow natural gas supplies outside North American to be used as LNG to supply markets that have few domestic resources. As a result, natural gas markets are expected to remain well supplied and prices relatively low in the mid-term, and many nations are expected to turn to natural gas, rather than more expensive or more carbon-intensive sources of electricity, to supply their future power needs.

### Liquid fuels and other petroleum

With world oil prices projected to return to relatively high levels, reaching $125 per barrel (in real 2009 dollars) in 2035, liquid fuels are the only energy source for power generation that does not grow on a worldwide basis. Nations are expected to respond to higher oil prices by reducing or eliminating their use of oil for generation—opting instead for more economical sources of electricity, including natural gas and nuclear. Even in the resource-rich Middle East, there is an effort to reduce the use of petroleum liquids for generation in favor of natural gas and other resources, in order to maximize revenues from oil exports. Worldwide, generation from liquid fuels decreases by 0.9 percent per year, from 1.0 trillion kilowatthours in 2008 to 0.8 trillion kilowatthours in 2035.

### Nuclear power

Electricity generation from nuclear power worldwide increases from 2.6 trillion kilowatthours in 2008 to 4.9 trillion kilowatthours in 2035 in the *IEO2011* Reference case, as concerns about energy security and greenhouse gas emissions support the development of new nuclear generating capacity. In addition, world average capacity utilization rates have continued to rise over time, from about 65 percent in 1990 to about 80 percent today, with some increases still anticipated in the future. Finally, most older plants now operating in OECD countries and in non-OECD Eurasia probably will be granted extensions to their operating licenses.

While *IEO2011* was in preparation, a large earthquake and tsunami struck the northeast coast of Japan, severely damaging nuclear power plants at Fukushima Daiichi [209]. Although the full extent of the damage remains unclear, the event is almost certain to have a negative impact on Japan's nuclear power industry, at least in the short term, and it is also likely to reduce projected nuclear generation from both existing and new facilities as governments formulate their policy responses to the disaster. The *IEO2011* Reference case was not revised to take the March 2011 natural disaster into account, but the uncertainty associated with nuclear power projections for Japan and for the rest of the world has increased.

A number of issues could slow the development of new nuclear power plants. In many countries, concerns about plant safety, radioactive waste disposal, and nuclear material proliferation could hinder plans for new installations. Moreover, the explosions at Japan's Fukushima Daiichi nuclear power plant in the aftermath of the March 2011 earthquake and tsunami could have long-term implications for the future of world nuclear power development in general. Even China—where large increases in nuclear capacity have been announced and are anticipated in the *IEO2011* Reference case—has indicated that it will halt approval processes for all new reactors until the country's nuclear regulator completes a "thorough safety review"—a process that could last for as long as a year [210]. Germany, Switzerland, and Italy already have announced plans to phase out or cancel all their existing and future reactors, indicating that some slowdown in the growth of nuclear power should be expected. High capital and maintenance costs may also keep some countries from expanding their nuclear power programs. Finally, a lack of trained labor resources, as well as limited global capacity for the manufacture of technological components, could keep national nuclear programs from advancing quickly.

*IEO2011* provides the status of international radioactive waste disposal programs in the box on page , which identifies the most common approaches to radioactive waste disposal and, where available, their costs and schedules. Storage and disposal costs remain an important life-cycle consideration in the decision to add nuclear generation capacity. Future IEOs will address supply chain uncertainties as well as uncertainties related to construction costs and uranium enrichment. Despite such uncertainties, the *IEO2011* Reference case projects continued growth in world nuclear power generation. The projection for nuclear electricity generation in 2035 is 9 percent higher than the projection published in last year's IEO.

Figure 76. World net electricity generation from nuclear power by region, 2008-2035
(trillion kilowatthours)

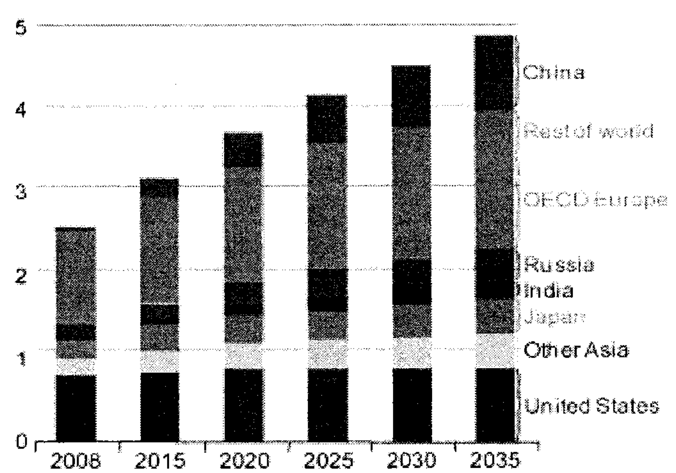



figure data

On a regional basis, the Reference case projects the strongest growth in nuclear power for the countries of non-OECD Asia (Figure 76), averaging 9.2 percent per year from 2008 to 2035, including increases of 10.3 percent per year in China and 10.8 percent per year in India. China leads the field with nearly 44 percent of the world's active reactor projects under construction in 2011 and is expected to install the most nuclear capacity over the period, building 106 gigawatts of net generation capacity by 2035 [211]. Outside Asia, nuclear generation grows the fastest in Central and South America, where it increases by an average of 4.2 percent per year. Nuclear generation worldwide increases by 2.4 percent per year in the Reference case.

To address the uncertainty inherent in projections of nuclear power growth over the long term, a two-step approach is used to formulate the outlook for nuclear power. In the short term (through 2020), projections are based primarily on the current activities of the nuclear power industry and national governments. Because of the long permitting and construction lead times associated with nuclear power plants, there is general agreement among analysts on which nuclear projects are likely to become operational in the short term. After 2020, the projections are based on a combination of announced plans or goals at the country and regional levels and consideration of other issues facing the development of nuclear power, including economics, geopolitical issues, technology advances, environmental policies, supply chain issues, and uranium availability.

## Hydroelectric, wind, geothermal, and other renewable generation

Renewable energy is the fastest-growing source of electricity generation in the *IEO2011* Reference case. Total generation from renewable resources increases by 3.1 percent annually, and the renewable share of world electricity generation grows from 19 percent in 2008 to 23 percent in 2035. More than 82 percent of the increase is in hydroelectric power and wind power. The contribution of wind energy, in particular, has grown swiftly over the past decade, from 18 gigawatts of net installed capacity at the end of 2000 to 121 gigawatts at the end of 2008—a trend that continues into the future. Of the 4.6 trillion kilowatthours of new renewable generation added over the projection period, 2.5 trillion kilowatthours (55 percent) is attributed to hydroelectric power and 1.3 trillion kilowatthours (27 percent) to wind (Table 13).

Although renewable energy sources have positive environmental and energy security attributes, most renewable technologies other than hydroelectricity are not able to compete economically with fossil fuels during the projection period except in a few regions or in niche markets. Solar power, for instance, is currently a "niche" source of renewable energy, but it can be economical where electricity prices are especially high, where peak load pricing occurs, or where government incentives are available. Government policies or incentives often provide the primary economic motivation for construction of renewable generation facilities.

Wind and solar are intermittent technologies that can be used only when resources are available. Once wind or solar facilities are built, however, their operating costs generally are much lower than the operating costs for fossil fuel-fired power plants. However, high construction costs can make the total cost to build and operate renewable generators higher than those for conventional plants. The intermittence of wind and solar can further hinder the economic competitiveness of those resources, because they are not operator-controlled and are not necessarily available when they would be of greatest value to the system. Although the technologies currently are not cost-effective, the use of energy storage (such as hydroelectric pumped storage, compressed air storage, and batteries) and the dispersal of wind and solar generating facilities over wide geographic areas could mitigate many of the problems associated with intermittency.

Changes in the mix of renewable fuels used for electricity generation differ between the OECD and non-OECD regions in the *IEO2011* Reference case. In the OECD nations, most of the hydroelectric resources that are both economical to develop and also meet environmental regulations already have been exploited. With the exceptions of Canada and Turkey, there are few large-scale hydroelectric projects planned for the future. As a result, most renewable energy growth in OECD countries comes from nonhydroelectric sources, especially wind and biomass. Many OECD countries, particularly those in Europe, have government policies, including feed-in tariffs (FITs),[30] tax incentives, and market share quotas, that encourage the construction of such renewable electricity facilities.

In non-OECD countries, hydroelectric power is expected to be the predominant source of renewable electricity growth. Strong growth in hydroelectric generation, primarily from mid- to large-scale power plants, is expected in China, India, Brazil, and a number of nations in Southeast Asia, including Malaysia and Vietnam. Growth rates for wind-powered generation also are high in non-OECD countries. The most substantial additions to electricity supply generated from wind power are expected for China.

The *IEO2011* projections for renewable energy sources include only marketed renewables. Non-marketed (noncommercial) biomass from plant and animal resources, while an important source of energy, particularly in the developing non-OECD economies, is not included in the projections, because comprehensive data on its use are not available. For the same reason, off-grid distributed renewables—renewable energy consumed at the site of production, such as off-grid photovoltaic (PV) panels—are not included in the projections.

## Global efforts to manage radioactive waste from nuclear power plants

Prospects for nuclear power generation have improved in recent years, as many nations have attempted to diversify the fuel mix for their power generation sectors away from fossil fuels while also addressing concerns about greenhouse gas emissions. Nuclear power generators do not emit the greenhouse gases produced by fossil fuel generators. However, they do produce radioactive waste that must be managed.

In the *IEO2011* Reference case, nuclear electricity generation nearly doubles from 2008 to 2035. Such an increase would be accompanied by significant increases in the accumulation of spent fuel rods and other nuclear waste in countries with nuclear power plants. Managing nuclear waste is a long-term issue. Governments must protect the public and environment from exposure to highly radioactive materials for hundreds or thousands of years into the future. And although there is general international agreement about how waste disposal should be approached, implementing management plans has proven to be politically complicated. As a result, few of the countries that currently have nuclear generation programs in operation have solidified their long-term plans for managing nuclear waste.

There are two forms of nuclear waste: spent nuclear fuel (SNF) and high-level radioactive waste (HLW), which results from the processing of SNF for re-use in nuclear power reactors. If SNF is not reprocessed, the normal management approach is long-term storage, either on site at nuclear power stations or at centralized interim storage facilities followed by deep geological disposal in a repository. This approach to waste management is known as the "direct disposal option."

In the United States, SNF is stored at the country's 104 operating nuclear reactors. In Sweden it is stored at a single site, the Central Interim Storage Facility for Spent Nuclear Fuel at Oskarshamn. France reprocesses its spent nuclear fuel to recover plutonium and uranium for use in fabricating new mixed-oxide fuel for its nuclear power plants, and it has successfully commercialized the process. Reprocessing greatly reduces the volume of nuclear waste for which disposal is necessary, but some components of the HLW cannot be recycled and must be vitrified (solidified in a glass-like matrix), stored, and eventually placed in a repository.

In selecting a nuclear waste management approach, several countries, including the United States, have opted for direct disposal in order to reduce the risk of nuclear weapons proliferation that is associated with the reprocessing option. The International Atomic Energy Agency's (IAEA) Joint Convention on the Safety of Spent Fuel Management and on the Safety of Radioactive Waste Management, which entered into force on June 18, 2001, recognizes that at the technical level disposal of nuclear waste in a deep geological repository ultimately represents the safest method of managing nuclear waste [212]. Many countries are investigating geological disposal and are committed to the approach in principle, including the 13 countries that produce more than 80 percent of the world's nuclear power: Belgium, Canada, China, Finland, France, Germany, Japan, South Korea, Spain, Sweden, Switzerland, the United Kingdom, and the United States.

Only a few countries provide reliable data on the costs of geological disposal. Their estimates generally are contained in national reports to the IAEA under the provisions of the Joint Convention or, alternatively, in published accounts of total life-cycle costs for their nuclear power systems. Disposal costs are affected by such factors as the type and quantity of waste that requires disposal, the design of the waste repository and its period of operation, and the country's waste management strategy (direct disposal or reprocessing). National cost estimates for the management of spent nuclear fuel vary widely:

- In the United States, a facility with storage capacity for 70,000 metric tons of heavy metal (MTHM) is estimated to cost $96.18 billion (2007 dollars) or about $707 per kilogram of heavy metal [213].
- In Japan a 29,647 MTHM storage facility is estimated to cost $25 billion (2007 dollars) or about $851 per kilogram of heavy metal [214].
- In Sweden a 9,741 MTHM storage facility is estimated to cost $3.4 billion (2007 dollars) or about $350 per kilogram of heavy metal [215].

Nuclear energy remains a key component of the world's electric power mix in the *IEO2011* Reference case. Countries with nuclear generation programs recognize the need for long-term planning for waste disposal, but the timing and costs of disposal are uncertain at best. Currently, no country has an operational disposal facility. With the United States recently having terminated its plan for disposal at Yucca Mountain in Nevada, the only countries likely to have operational deep geological repositories by 2025 are Finland, France, and Sweden. Others, including China and Spain, may not have established geological repositories until as late as 2050 (Table 12). Implementing timely nuclear waste management strategies will reduce uncertainties in the nuclear fuel cycle as well as the ultimate cost of disposal, but it remains to be seen how successful the international community will be in implementing such strategies.

## Regional electricity outlooks

In the *IEO2011* Reference case, the highest growth rates for electricity generation are in non-OECD nations, where strong economic growth and rising personal incomes drive the growth in demand for electric power. In OECD countries—where electric power infrastructures are relatively mature, national populations generally are expected to grow slowly or decline, and GDP growth is slower than in the developing nations—demand for electricity grows much more slowly. Electricity generation in non-OECD nations increases by 3.3 percent per year in the Reference case, as compared with 1.2 percent per year in OECD nations.

## OECD electricity

### Americas

The countries of the OECD Americas (the United States, Canada, Chile, and Mexico) currently account for the largest regional share of world electricity generation, with 26 percent of the total in 2008. That share declines as non-OECD nations experience fast-paced growth in demand for electric power. In 2035, the nations of the OECD Americas together account for only 19 percent of the world's net electric power generation.

Figure 77. OECD Americas net electricity generation by region, 2008-2035
(trillion kilowatthours)

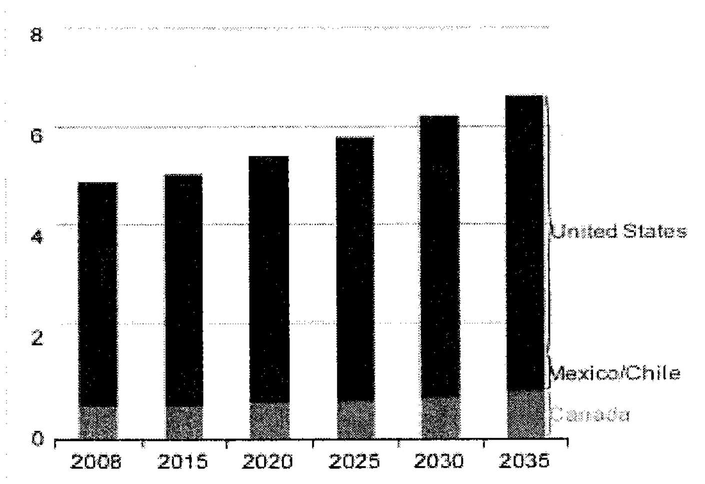



figure data

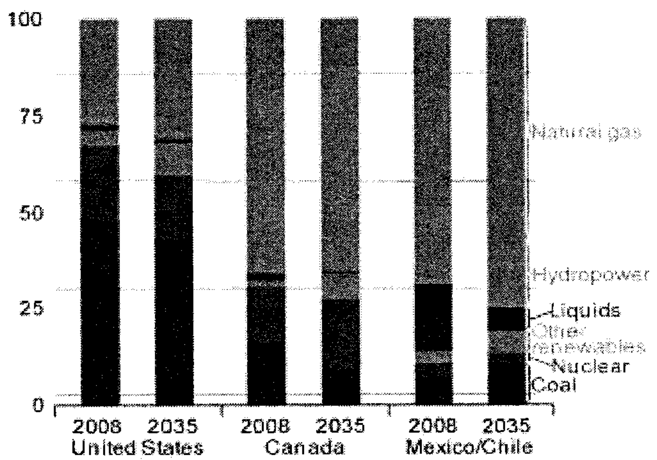
The United States is by far the largest consumer of electricity in the region (Figure 77). U.S. electricity generation—including both generation by electric power producers and on-site generation—increases slowly, at an average annual rate of 0.8 percent from 2008 to 2035. Canada, like the United States, has a mature electricity market, and its generation increases by 1.4 percent per year over the same period. Mexico/Chile's electricity generation grows at a faster rate—averaging 3.2 percent per year through 2035—reflecting the current less-developed state of their electric power infrastructure (and thus the greater potential for expansion) relative to Canada and the United States.

There are large differences in the mix of energy sources used to generate electricity in the four countries that make up the OECD Americas, and those differences are likely to become more pronounced in the future (Figure 78). In the United States, coal is the leading source of energy for power generation, accounting for 48 percent of the 2008 total. In Canada, hydroelectricity provided 60 percent of the nation's electricity generation in 2008. Most of Mexico/Chile's electricity generation is currently fueled by petroleum-based liquid fuels and natural gas, which together accounted for 66 percent of total generation in 2008. The predominant fuels for generation in the United States and Canada are expected to lose market share by 2035, although electricity generation continues to be added. Coal-fired generation declines to 43 percent of the U.S. total, and hydropower falls to 54 percent of Canada's total in 2035. In contrast, in Mexico/Chile, natural-gas-fired generation increases from 48 percent of the total in 2008 to 58 percent in 2035.

figure data

Generation from renewable energy sources in the United States increases in response to requirements in more than half of the 50 States for minimum renewable shares of electricity generation or capacity. Although renewable generation in 2035 in the *IEO2011* Reference case is 17 percent lower than in last year's outlook (due to a variety of factors, including lower electricity demand, a significant increase in the availability of shale gas, and revised technology and policy assumptions), the share of renewable-based generation is expected to grow from 9.7 percent in 2008 to 14.3 percent in 2035. The projection for electricity generation from other renewables sources also has dropped, as a result of lower expectations for biomass co-firing. U.S. Federal subsidies for renewable generation are assumed to expire as enacted. If those subsidies were extended, however, a larger increase in renewable generation would be expected.

Figure 78. OECD Americas net electricity generation by fuel, 2008-2035
(percent of total)




Electricity generation from nuclear power plants accounts for 16.9 percent of total U.S. generation in 2035 in the *IEO2011* Reference case. Title XVII of the U.S. Energy Policy Act of 2005 (EPACT2005, Public Law 109-58) authorized the U.S. Department of Energy to issue loan guarantees for innovative technologies that "avoid, reduce, or sequester greenhouse gases." In addition, subsequent legislative provisions in the Consolidated Appropriation Act of 2008 (Public Law 110-161) allocated $18.5 billion in guarantees for nuclear power plants [216]. That legislation supports a net increase of about 10 gigawatts of nuclear power capacity, which grows from 101 gigawatts in 2008 to 111 gigawatts in 2035. The increase includes 3.8 gigawatts of expanded capacity at existing plants and 6.3 gigawatts of new capacity. The *IEO2011* Reference case includes completion of a second unit at the Watts Bar nuclear site in Tennessee, where construction was halted in 1988 when it was nearly 80 percent complete. Four new U.S. nuclear power plants are completed by 2035, all brought on before 2020 to take advantage of Federal financial incentives. One nuclear unit, Oyster Creek, is projected to be retired at the end of 2019, as announced by Exelon in December 2010. All other existing nuclear units continue to operate through 2035 in the Reference case.

In Canada, generation from natural gas increases by 3.8 percent per year from 2008 to 2035, nuclear by 2.2 percent per year, hydroelectricity by 0.9 percent per year, and wind by 9.9 percent per year. Oil-fired generation and coal-fired generation, on the other hand, decline by 1.0 percent per year and 0.6 percent per year, respectively.

In Ontario—Canada's largest provincial electricity consumer—the government plans to close its four remaining coal-fired plants (Atikokan, Lambton, Nanticoke, and Thunder Bay) by December 31, 2014, citing environmental and health concerns [217]. Units 1 and 2 of Lambton and units 3 and 4 of Nanticoke were decommissioned in 2010 [218]. The government plans to replace coal-fired generation with natural gas, nuclear, hydropower, and wind. It also plans to increase conservation measures. With the planned retirements in Ontario, Canada's coal-fired generation declines from about 104 billion kilowatthours in 2008 to 88 billion kilowatthours in 2035.

The renewable share of Canada's overall generation remains roughly constant throughout the projection. Hydroelectric power is, and is expected to remain, the primary source of electricity in Canada. From 60 percent of the country's total generation in 2008, hydropower falls to 54 percent in 2035. As one of the few OECD countries with large untapped hydroelectric potential, Canada currently has several large- and small-scale hydroelectric facilities either planned or under construction. Hydro-Quebec is continuing the construction of a 768-megawatt facility near Eastmain and a smaller 150-megawatt facility at Sarcelle in QuÃ©bec, both of which are expected to be fully commissioned by 2012 [219]. Other hydroelectric projects are under construction, including the 1,550-megawatt Romaine River project in Quebec and the 200-megawatt Wuskwatim project in Manitoba [220]. The *IEO2011* Reference case does not anticipate that all planned projects will be constructed, but given Canada's past experience with hydropower and the commitments for construction, new hydroelectric capacity accounts for 25,563 megawatts of additional renewable capacity added in Canada between 2008 and 2035.

Wind-powered generation, in contrast, is the fastest-growing source of new energy in Canada, with its share of total generation increasing from less than 1 percent in 2008 to 5 percent in 2035. Canada has plans to continue expanding its wind power capacity, from 4.0 gigawatts of installed capacity at the end of 2010 [221] to nearly 16.6 gigawatts in 2035 in the Reference case. Growth in wind capacity has been so rapid that Canada's federal wind incentive program, "ecoENERGY for

Renewable Power," which targeted the deployment of 4 gigawatts of renewable energy by 2011, allocated all of its funding and met its target by the end of 2009 [222].

In addition to the incentive programs of Canada's federal government, several provincial governments have instituted their own incentives to support the construction of new wind capacity. After the success of its Renewable Energy Standard Offer Program, Ontario enacted a feed-in-tariff that pays all sizes of renewable energy generators between 10 cents and 80 cents (Canadian) per kilowatthour, depending on project type, for electricity delivered to the grid [223]. The two programs have helped support robust growth in wind installations over the past several years, and installed wind capacity in the province has risen from 0.6 megawatts in 1995 to 1,457 megawatts in February 2011 [224]. Continued support from Canada's federal and provincial governments—along with the sustained higher fossil fuel prices in the *IEO2011* Reference case—is expected to provide momentum for the projected increase in the country's use of wind power for electricity generation.

The combined electricity generation of Mexico and Chile increases by an average of 3.2 percent annually from 2008 to 2035—more than double the rate for Canada and almost quadruple the rate for the United States. In Mexico, the government has recognized the need for the country's electricity infrastructure to keep pace with the fast-paced growth anticipated for electricity demand. In July 2007, the government unveiled its 2007-2012 National Infrastructure Program, which included plans to invest $25.3 billion to improve and expand electricity infrastructure [225]. As part of the program, the government has set a goal to increase installed generating capacity by 8.6 gigawatts from 2006 to 2012 [226].

Natural-gas-fired generation in Mexico and Chile more than doubles in the Reference case, from 147 billion kilowatthours in 2008 to 418 billion kilowatthours in 2035. With Mexico's government expected to implements plans to reduce the country's use of diesel and fuel oil for power generation [227], the country's demand for natural gas strongly outpaces growth in electricity production, leaving it dependent on pipeline imports from the United States and LNG from other countries. Currently, Mexico has one LNG import terminal, Altamira, operating on the Gulf Coast and another, Costa Azul, on the Pacific Coast. A contract tender for a third terminal at Manzanillo, also on the Pacific Coast, was awarded in March 2008, and the project is scheduled for completion by 2011 [228].

Chile also has been trying to increase natural gas use for electricity generation in order to diversify its fuel mix. In 2008, nearly 40 percent of the country's total generation came from hydropower, which can be problematic during times of drought. An unusually hot and dry summer in Chile in 2010-2011 has resulted in the country's worst drought in several decades and threatens power shortages [229]. The government has instituted emergency measures to ensure power supplies, launching a nationwide energy conservation program and also increasing imports of LNG through its two regasification terminals. Although Chile can import natural gas from Argentina through existing pipelines, supplies have not always been reliable. Beginning in 2004, Argentina began to restrict its gas exports to Chile because it was unable to meet its own domestic supplies, leading Chile to develop its LNG import capacity [230].

Most of the renewable generation in Chile and Mexico comes from hydroelectric dams. Hydroelectric resources provide about 85 percent of the region's current renewable generation mix, with another 9 percent coming from geothermal energy. There are plans to expand hydroelectric power in both countries in the future. In the *IEO2011* Reference case, hydroelectric power accounts for almost 75 percent of Mexico/Chile's total net generation from renewable energy sources in 2035. In Mexico, there are two major hydroelectric projects underway: the 750-megawatt La Yesca facility, scheduled for completion by 2012, and the planned 900-megawatt La Parota project, which has been delayed and may not be completed until 2018 [231].

In addition to efforts to diversify its electricity fuel mix, Chile has a number of new hydroelectric plants planned or under construction. In October 2010, the 150-megawatt La Higuera and 158-megawatt La Confluencia hydro projects on the Tinguiririca River were completed [232]. The two run-of-river projects were constructed in a joint venture by Australia's Pacific Hydro and Norway's SN Power Invest. Pacific Hydro also has plans to construct another 650 megawatts of hydroelectric capacity on Chile's Upper Cachapoal River. Construction on the first phase of the development began in 2009. The first hydro plant in the system, the 111-megawatt Chacayes power plant, is scheduled for completion in October 2011. The entire development should be completed in 2019, when the 78-megawatt Las Maravillas project is scheduled to begin operation [233].

There is virtually no wind or solar generation in Mexico at present, but the Mexican government's goal of installing 2.5 gigawatts of wind capacity on the Tehuantepec Isthmus by 2012 has encouraged wind development in the short term [234]. The 161-megawatt Los Vergeles project and the Oaxaca II, III, and IV projects—totaling more than 300 megawatts—are due for completion in 2011 and 2012, respectively. In Baja California even larger projects are under development, such as the 1,200-megawatt Sempra and the 400-megawatt Union Fenosa projects [235]. Further, Mexico's goal of reducing national greenhouse gas emissions to 50 percent of 2002 levels by 2050 is expected to spur wind and solar installations in the future [236].

Chile expanded its total installed wind capacity to 167 megawatts in early 2011 and has granted environmental approval to an additional 1,500 megawatts of wind projects [237]. Still, the penetration of wind and solar generating capacity in Chile remains modest throughout the projection, with their share of Mexico and Chile's combined total electricity generation rising from less than 0.1 percent in 2008 to 3 percent in 2035.

## OECD Europe

Electricity generation in the nations of OECD Europe increases by an average of 1.2 percent per year in the *IEO2011* Reference case, from 3.4 trillion kilowatthours in 2008 to 4.8 trillion kilowatthours in 2035. Because most of the countries in OECD Europe have relatively stable populations and mature electricity markets, most of the region's growth in electricity demand is expected to come from those nations with more robust population growth (including Turkey, Ireland, and Spain) and from the newest OECD members (including the Czech Republic, Hungary, Poland, and Slovenia), whose projected economic growth rates exceed the OECD average. In addition, with environmental concerns remaining prominent in the region, there is a concerted effort in the industrial sector to switch from coal and liquid fuels to electricity.

Figure 79. OECD Europe net electricity generation by fuel, 2008-2035
(trillion kilowatthours)

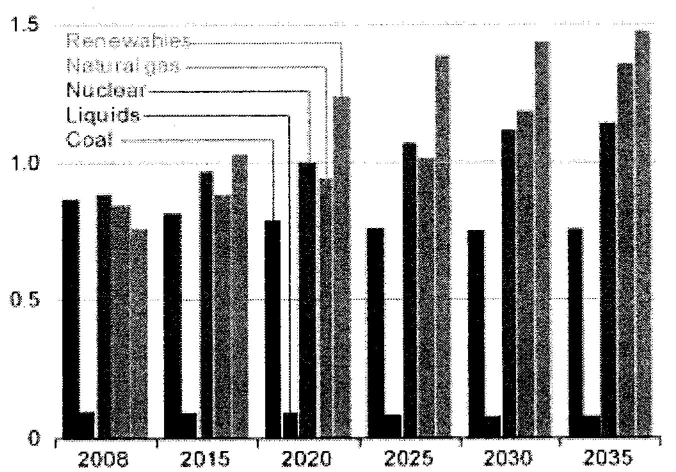



figure data

Renewable energy is OECD Europe's fastest-growing source of electricity generation in the Reference case (Figure 79), increasing by 2.5 percent per year through 2035. The increase is almost entirely from wind and solar. OECD Europe's leading position worldwide in wind power capacity is maintained through 2035, with growth in generation from wind sources averaging 6.4 percent per year, even though the Reference case assumes no enactment of additional legislation to limit greenhouse gas emissions. Strong growth in offshore wind capacity is underway, with 883 megawatts added to the grid in 2010, representing a 51-percent increase over the amount of capacity added in 2009 [238].

The United Kingdom is expected to spearhead the growth in OECD Europe's offshore wind capacity. Although there is debate within the country over the costs and benefits of offshore wind power, the 300-megawatt Thanet Wind Farm, the world's largest, was completed in September 2010 [239]. Work is also continuing on other major projects, including the 1,000-megawatt London Array, for which the first foundation was laid in March 2011 [240].

The growth of nonhydropower renewable energy sources in OECD Europe is encouraged by some of the world's most favorable renewable energy policies. The European Union set a binding target to produce 21 percent of electricity generation from renewable sources by 2010 [241] and reaffirmed the goal of increasing renewable energy use with its December 2008 "climate and energy policy," which mandates that 20 percent of total energy production must come from renewables by 2020 [242]. Approximately 18 percent of the European Union's electricity came from renewable sources in 2008.

The *IEO2011* Reference case does not anticipate that all future renewable energy targets in the European Union will be met on time. Nevertheless, current laws are expected to lead to the construction of more renewable capacity than would have occurred in their absence. In addition, some individual countries provide economic incentives to promote the expansion of renewable electricity. For example, Germany, Spain, and Denmark—the leaders in OECD Europe's installed wind capacity—have enacted feed-in tariffs that guarantee above-market rates for electricity generated from renewable sources and, typically, last for 20 years after a project's completion. As long as European governments support such price premiums for renewable electricity, robust growth in renewable generation is likely to continue.

Exceptionally generous feed-in tariffs have been falling out of favor in recent years, however. Before September 2008, Spain's solar subsidy led to an overabundance of solar PV projects. When the Spanish feed-in tariff was lowered after September 2008, a PV supply glut or "solar bubble" resulted, driving down the price of solar panels and lowering profits throughout the industry [243]. The Spanish government is now set to reduce its tariffs by a further 45 percent for large ground -based sites, in view of the country's large public deficit and the fear of creating another solar bubble [244]. Germany has taken a similar approach and will cut its feed-in tariff for ground PV units by 15 percent, effective in the summer of 2011 [245]. Italy, with the third-largest installed PV capacity in OECD Europe, is also lowering its solar feed-in tariff in June 2011, after experiencing a financially unsustainable 128-percent increase in solar PV output between November 2009 and November 2010 [246].

Natural gas is the second fastest-growing source of power generation after renewables in the outlook for OECD Europe, increasing at an average rate of 1.8 percent per year from 2008 to 2035. Growth is projected to be more robust than the 1.3-percent annual increase in last year's outlook, as prospects for the development of unconventional sources of natural gas in the United States and other parts of the world help to keep world markets well supplied and global prices relatively low. As a result, natural gas is more competitive in European markets in the *IEO2011* Reference case than it was in *IEO2010*.

Before the Fukushima disaster in Japan, prospects for nuclear power in OECD Europe had improved markedly in recent years, and many countries were reevaluating their programs to consider plant life extensions or construction of new nuclear generating capacity. In the aftermath of Fukushima, it appears that many OECD nations are reconsidering their plans. Although the full extent to which European governments might withdraw their support for nuclear power is uncertain, some countries already have reversed their nuclear policies. For example, the German government has announced plans to close all nuclear reactors in the country by 2022 [247]; the Swiss Cabinet has decided to phase out nuclear power by 2034 [248]; and Italian voters, in a country-wide referendum, have rejected plans to build nuclear power plants in Italy [249]. In addition, the European Commission has announced that it will conduct a program of stress tests on nuclear reactors operating in the European Union. (Turkey, in contrast, has announced that it will proceed with construction of the country's first nuclear power plant [250].) Still, environmental concerns and the importance of energy security provide support for future European nuclear generation. With no phaseout of nuclear power anticipated in the IEO2011 Reference case, nuclear capacity in OECD Europe increases by a net 19 gigawatts from 2008 to 2035.

Coal accounted for 25 percent of OECD Europe's net electricity generation in 2008, but concerns about the contribution of carbon dioxide emissions to climate change could reduce that share in the future. In the *IEO2011* Reference case, electricity from coal slowly loses its prominence in OECD Europe, declining by 0.5 percent per year from 2008 to 2035 and ultimately falling behind renewables, natural gas, and nuclear energy as a source of electricity. Coal consumption in the electric power sector is not decreasing uniformly in all countries in OECD Europe, however. Spain's Coal Decree, which went into force in February 2011, subsidizes the use of domestic coal in Spanish power plants. The policy is expected to result in more electricity generation from coal-fired plants at least through 2014, when the subsidy is scheduled to expire [251].

## OECD Asia

Total electricity generation in OECD Asia increases by an average of 1.2 percent per year in the Reference case, from 1.7 trillion kilowatthours in 2008 to 2.4 trillion kilowatthours in 2035. Japan accounted for the largest share of electricity generation in the region in 2008 and continues to do so throughout the projection period, despite having the slowest-growing electricity market in the region and the slowest among all OECD countries, averaging 0.8 percent per year, as compared with 1.3 percent per year for Australia/New Zealand and 2.0 percent per year for South Korea (Figure 80). Japan's electricity markets are well established, and its aging population and relatively slow projected economic growth translate into slow growth in demand for electric power. In contrast, Australia/New Zealand and South Korea are expected to see more robust economic growth and population growth, leading to more rapid growth in demand for electricity.

**Figure 80. OECD Asia net electricity generation by fuel, 2008-2035**
(trillion kilowatthours)

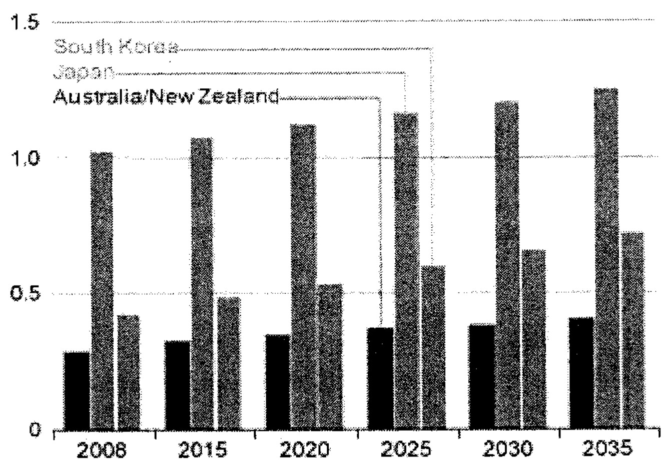



figure data

The fuel mix for electricity generation varies widely among the three economies that make up the OECD Asia region. In Japan, natural gas, coal, and nuclear power make up the bulk of the current electric power mix, with natural gas and nuclear accounting for about 51 percent of total generation and coal another 26 percent. The remaining portion is split between renewables and petroleum-based liquid fuels. Japan's reliance on nuclear power increases over the projection period, from 24 percent of total generation in 2008 to 33 percent in 2035. The natural gas share of generation declines slightly over the same period, from 27 percent to 26 percent, and coal's share declines to 18 percent, being displaced by nuclear and renewable energy sources.

On March 11, 2011, a devastating, magnitude 9.0 earthquake, followed by a tsunami, struck northeastern Japan, resulting in extensive loss of life and triggering a nuclear disaster at the Fukushima Daiichi nuclear power plants. At present, it is impossible to assess the ultimate impact on Japan's nuclear program, and *IEO2011* makes no attempt to incorporate the ultimate effects of the earthquake in the Reference case. In the immediate aftermath of the earthquake, reactors at Japan's Fukushima Daini and Onagawa nuclear facilities were successfully shut down, and they will not be returned to operation until they have undergone stringent safety reviews [252]. The six reactors at Fukushima Daiichi were damaged beyond repair, removing of 4.7 gigawatts of generating capacity from the grid. Although power had been restored in most of the affected areas by June 2011, the temporary and permanent losses of nuclear power capacity from Japan's electricity grid (in addition to a substantial amount of coal-fired capacity that also remains shut down) will make it difficult for power generators to meet demand in the summer months of 2011 (June, July, and August), when electricity consumption typically is very high [253].

Currently, Japan is reconsidering its electricity supply policies. In May, Prime Minister Naoto Kan stated that the plan to increase the nuclear power share of the country's electricity supply, from about 26 percent at present to 50 percent by 2030, "will have to be set aside" [254]. Instead, the government plans to pursue an aggressive expansion of renewable energy capacity, especially solar power. Japan generates only about 6 percent of its primary energy from renewable energy sources (including hydroelectricity), but government policies and incentives to increase solar power will improve the growth of the energy source in the future. In the *IEO2011* Reference case, electricity generation from solar energy increases by 11.5 percent per year from 2008 to 2035, making solar power Japan's fastest-growing source of renewable energy (although it starts from a negligible amount in 2008). In November 2009, the government initiated a feed-in tariff incentive to favor the development of solar power [255]. Wind-powered generation in Japan also increases strongly in the Reference case, by an average of 8.1 percent per year. In the wake of the nuclear disaster, it is likely that additional government incentives for renewable energy sources will follow. Both solar and wind power, however, remain minor sources of electricity, supplying 3 percent and 2 percent of total generation in 2035, respectively, as compared with hydropower's 8-percent share of the total.

Australia and New Zealand, as a region, rely on coal for about 66 percent of electricity generation, based largely on Australia's rich coal resource base (9 percent of the world's total coal reserves). The remaining regional generation is supplied by natural gas and renewable energy sources—mostly hydropower, wind, and, in New Zealand, geothermal.

Australia continues to make advances in wind energy, with 1,712 megawatts of capacity installed at the end of 2009 and a further 588 megawatts under construction [256]. To help meet its 2025 goal of having 90 percent of electricity generation come from renewable sources, New Zealand is focusing on harnessing more of its geothermal potential [257]. Construction of the 250-megawatt Tauhara II project, currently under review by the country's Environmental Protection Authority, would alone power all the homes in the Wellington metro area [258]. The Australia/New Zealand region uses negligible amounts of oil for electricity generation and no nuclear power, and that is not expected to change over the projection period. Natural-gas-fired generation is expected to grow strongly in the region, at 4.0 percent per year from 2008 to 2035, reducing the coal share to 39 percent in 2035.

In South Korea, coal and nuclear power currently provide 42 percent and 34 percent of total electricity generation, respectively. Natural-gas-fired generation grows quickly in the Reference case, but despite a near doubling of electricity generation from natural gas, its share of total generation increases only slightly, from 19 percent in 2008 to 21 percent in 2035. Coal and nuclear power continue to provide most of South Korea's electricity generation, with a combined 73 percent of total electricity generation in 2035.

## Non-OECD electricity

### Non-OECD Europe and Eurasia

Total electricity generation in non-OECD Europe and Eurasia grows at an average rate of 1.4 percent per year in the *IEO2011* Reference case, from 1.6 trillion kilowatthours in 2008 to 2.3 trillion kilowatthours in 2035. Russia, with the largest economy in non-OECD Europe and Eurasia, accounted for about 60 percent of the region's total generation in 2008 and is expected to retain approximately that share throughout the period (Figure 81).

Figure 81. Non-OECD Europe and Eurasia electricity generation by region, 2008-2035
(trillion kilowatthours)

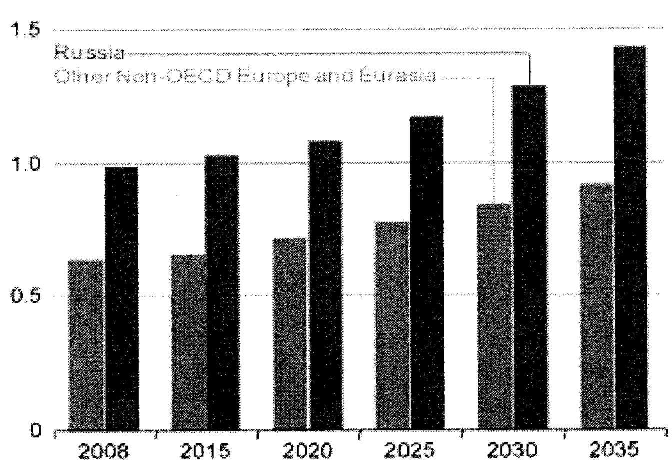



figure data

Natural gas and nuclear power supply much of the growth in electricity generation in the region. Although non-OECD Europe and Eurasia has nearly one-third of the world's total proved natural gas reserves, some countries (notably, Russia) plan to export natural gas instead of using it to fuel electricity generation. As a result, the region's natural-gas-fired generation grows modestly in the outlook, at an average rate of 0.7 percent from 2008 to 2035.

Generation from nuclear power grows strongly in the region, averaging 3.0 percent per year. Much of the increase is expected in Russia, which continues to shift generation from natural gas to nuclear, because natural gas exports are more profitable than the domestic use of natural gas for electricity generation.

In 2006, the Russian government released Resolution 605, which set a federal target program (FTP) for nuclear power development. Although the FTP was updated and scaled back in July 2009 as a result of the recession, 10 nuclear power reactors still are slated for completion by 2016, adding a potential 9 gigawatts of capacity. According to the Russian plan, another 44 reactors are to be constructed, increasing Russia's total nuclear generating capacity to 42 gigawatts by 2024. By 2030, the plan would bring the total to nearly 50 gigawatts and increase nuclear generation to 25 or 30 percent of total generation. In January 2010, the Russian government approved an FTP that would shift the focus of the nuclear power industry to fast reactors with a closed fuel cycle. Life extensions have been completed for roughly 30 percent of Russia's operating reactors, and the installed capacity of most reactors has been uprated [259]. In the *IEO2011* Reference case, Russia's existing 23 gigawatts of nuclear generating capacity is supplemented by a net total of 5 gigawatts in 2015 and another 23 gigawatts in 2035.

Renewable generation in non-OECD Europe and Eurasia, almost entirely from hydropower facilities, increases by an average of 1.9 percent per year, largely as a result of repairs and expansions at existing sites. The repairs include reconstruction of turbines in the 6.4-gigawatt Sayano-Shushenskaya hydroelectric plant, which was damaged in an August 2009 accident [260]. Four of the plant's 640-megawatt generators are currently operational, and full restoration of the dam is expected to be completed by 2014 [261]. Notable new projects include the 3-gigawatt Boguchanskaya Hydroelectric Power Station in Russia and the 3.6-gigawatt Rogun Dam in Tajikistan. Construction of the Boguchanskaya station began in 1980, and work was started on Rogun in 1976. However, work on both projects ceased when the former Soviet Union experienced economic difficulties in the 1980s.

Despite the recent recession, construction continues on Boguchanskaya, which is on track for completion by 2012 [262]. Although Tajikistan's president announced in May 2008 that construction work on Rogun Dam had resumed, its prospects are less favorable [263]. Neighboring Uzbekistan strongly opposes the dam, fearing that it will reduce the water supply that supports the Uzbek cotton industry [264]. Furthermore, only $200 million of the $4 billion needed to complete the hydroelectric plant has been raised so far, enough to support the construction work for just 2 more years [265].

Other than increases in hydropower, only modest growth in renewable generation is projected for the nations of non-OECD Europe and Eurasia, given the region's access to fossil fuel resources and lack of financing available for relatively expensive renewable projects. In the *IEO2011* Reference case, nonhydropower renewable capacity in the region increases by only 5 gigawatts from 2008 to 2035. Although total growth in nonhydropower renewable generation is projected to be small, Romania is one nation in the region that is moving ahead with wind energy projects: its 348-megawatt Fantanele wind farm is on track to be completed in late 2010, and the nearby Cogealac wind farm (253 megawatts) is due for commissioning in 2011 [266].

## Non-OECD Asia

Non-OECD Asia—led by China and India—has the fastest projected growth rate for electric power generation worldwide, averaging 4.0 percent per year from 2008 to 2035 in the Reference case. Although the global economic recession had an impact on the region's short-term economic growth, the economies of non-OECD Asia have led the recovery and are projected to expand strongly in the long term, with corresponding increases in demand for electricity in both the building and industrial sectors. Total electricity generation in non-OECD Asia grows by 49 percent, from 5.0 trillion kilowatthours in 2008 to 14.3 trillion kilowatthours in 2035, with electricity demand increasing by 46 percent from 2015 to 2025 and by another 32 percent from 2025 to 2035. In 2035, net electricity generation in non-OECD Asia totals 14.3 trillion kilowatthours in the Reference case. Non-OECD Asia is the world's fastest-growing regional market for electricity in *IEO2011*, accounting for 41 percent of world electricity generation in 2035.

Coal is used to fuel more than two-thirds of electricity generation in non-OECD Asia (Figure 82), led by coal-fired generation in China and India. Both countries rely heavily on coal to produce electric power. In 2008, coal's share of generation was an estimated 80 percent in China and 68 percent in India. Under existing policies, it is likely that coal will remain the predominant source of power generation in both countries. In the IEO2011 Reference case, coal's share of electricity generation declines to 66 percent in China and 51 percent in India in 2035.

Figure 82. Non-OECD Asia net electricity generation by fuel, 2008-2035
(trillion kilowatthours)

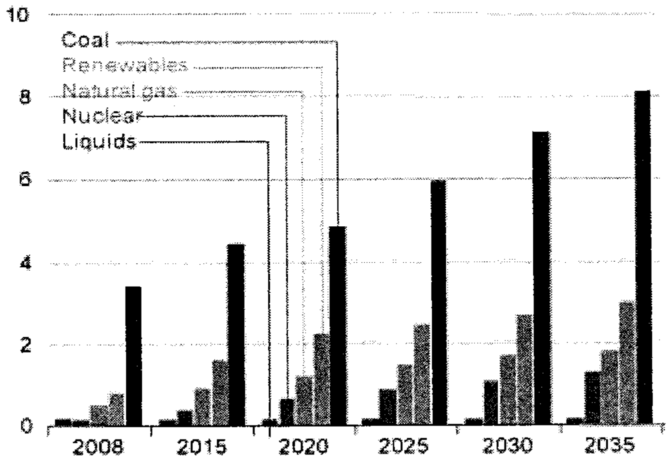



figure data

At present, China is installing approximately 900 megawatts of coal-fired capacity (equivalent to one large coal-fired power plant) per week. However, it also has been retiring old, inefficient plants to help slow the rate of increase in the nation's carbon intensity. From 2006 to 2010, China retired almost 71 gigawatts of coal-fired capacity, including 11 gigawatts in 2010, and it plans to retire an additional 8 gigawatts in 2011 [267].

Non-OECD Asia leads the world in installing new nuclear capacity in the *IEO2011* Reference case, accounting for 54 percent of the net increment in nuclear capacity worldwide (or 144 gigawatts of the total 266-gigawatt increase). China, in particular, has ambitious plans for nuclear power, with more than 27 nuclear power plants currently under construction and a total of 106 gigawatts of new capacity expected to be installed by 2035.

There is significant uncertainty in the *IEO2011* Reference case projections for China's nuclear capacity. Officially, China's nuclear capacity targets are 70 to 86 gigawatts by 2020 and 200 gigawatts by 2030—targets that the Chinese government has been increasing since 2008, when the target was 40 gigawatts by 2020 [268]. Factors that may cause China to undershoot its official targets include limited global capacity of heavy forging facilities required for the manufacture of Generation III reactor components and potential difficulties in training the large number of engineers and regulators needed to operate and monitor the planned power plants. On the other hand, an estimated 226 gigawatts of new capacity has advanced beyond the pre-feasibility study phase, including reactors in at least 20 provinces that are not approved for the national plan [269]. The impact of the March 2011 disaster at Japan's Fukushima Daishi nuclear power plant may also have a negative impact on the pace of China's nuclear power program. In the aftermath of the disaster, China announced it would halt approval processes for all new reactors until the country's nuclear regulator completes a "thorough safety review"—a process that could last for as long as a year [270].

The *IEO2011* Reference case assumes that the global lack of heavy forging facilities and the long lead times needed to build or upgrade forging facilities, build new nuclear power plants, and train new personnel will cause China's nuclear power industry to grow more slowly than in official government predictions. Nonetheless, the 115 gigawatts of nuclear capacity projected for 2035 is a 53-percent increase over last year's Reference case. In the *IEO2011* Reference case, the nuclear share of China's total electricity generation increases from 2 percent in 2008 to 10 percent in 2035.

India also has plans to boost its nuclear power generating capacity. From 4 gigawatts of installed nuclear power capacity in operation in 2011, India has set an ambitious goal of increasing its nuclear generating capacity to 20 gigawatts by 2020 and to as much as 63 gigawatts by 2032 [271]. Currently, five nuclear reactors are under construction, three of which are scheduled for completion by the end of 2011 [272]. The *IEO2011* Reference case assumes a slower increase in nuclear capacity than anticipated by India's government, to 16 gigawatts in 2020 and 28 gigawatts in 2035.

In addition to China and India, several other countries in non-OECD Asia are expected to begin or expand nuclear power programs. In the Reference case, new nuclear power capacity is installed in Taiwan, Vietnam, Indonesia, and Pakistan by 2020. Concerns about security of energy supplies and greenhouse gas emissions lead many nations in the region to diversify their fuel mix for power generation by adding a nuclear component.

Electricity generation from renewable energy sources in non-OECD Asia grows at an average annual rate of 4.9 percent, increasing the renewable share of the region's total generation from 17 percent in 2008 to 21 percent in 2035. Small-, mid-, and large-scale hydroelectric facilities all contribute to the projected growth. Several countries in non-OECD Asia have hydropower facilities either planned or under construction, including Vietnam, Malaysia, Pakistan, and Myanmar (the former Burma). Almost 50 hydropower facilities, with a combined 3,398 megawatts capacity, are under construction in Vietnam's Son La province, including the 2,400-megawatt Son La and 520-megawatt Houi Quang projects, both of which are scheduled for completion before 2015 [273]. The remaining facilities are primarily micro- and mini-hydroelectric power plants. Malaysia expects to complete its 2,400-megawatt Bakun Dam by the end of 2011, although the project has experienced delays and setbacks in the past [274].

Pakistan and Myanmar also have substantial hydropower development plans, but those plans have been discounted in the *IEO2011* Reference case to reflect the two countries' historical difficulties in acquiring foreign direct investment for infrastructure projects. Pakistan's electricity development plans have been further hampered by floods that occurred in 2010; power plants that had been in need of refurbishment are now severely damaged or destroyed [275]. Nearly 150 of the 200 small hydroelectric plants in the northern Khyber-Pakhtunkhwa province were destroyed by the floods and may take years to rebuild [276].

India has plans to more than double its installed hydropower capacity by 2030. In its Eleventh and Twelfth Five-Year Plans, which span 2008 through 2017, India's Central Electricity Authority has identified nearly 41 gigawatts of hydroelectric capacity that it intends to build. Nearly one-half of the planned capacity is to be built in the Uttarakhand region. However, environmental concerns recently led to the rejection of two proposed projects in the region, totaling 860 megawatts, which underscores the uncertainty associated with estimating India's future hydroelectric development. Despite $150 million already invested in the 600-megawatt Loharinag Pala project, construction on the project has also been halted, and its future is uncertain [277]. Although the *IEO2011* Reference case does not assume that all the planned capacity will be completed, more than one-third of the announced projects are under construction already and are expected to be completed by 2020 [278].

Like India, China has many large-scale hydroelectric projects under construction. The final generator for the 18.2-gigawatt Three Gorges Dam project went on line in October 2008, and the Three Gorges Project Development Corporation plans to increase the project's total installed capacity further, to 22.4 gigawatts by 2012 [279]. In addition, work continues on the 12.6-gigawatt Xiluodu project on the Jinsha River, which is scheduled for completion in 2015 as part of a 14-facility hydropower development plan [280]. China also has the world's second-tallest dam (at nearly 985 feet) currently under construction, as part of the 3.6-gigawatt Jinping I project on the Yalong River. The dam scheduled for completion in 2014 as part of a plan by the Ertan Hydropower Development Company to construct 21 facilities with 29.2 gigawatts of hydroelectric capacity on the Yalong [281].

The Chinese government has set a 300-gigawatt target for hydroelectric capacity in 2020. Including those mentioned above, the country has a sufficient number of projects under construction or in development to meet the target. China's aggressive hydropower development plan is expected to increase hydroelectricity generation by 3.2 percent per year, more than doubling the country's total hydroelectricity generation by 2035.

Although hydroelectric projects dominate the renewable energy mix in non-OECD Asia, generation from nonhydroelectric renewable energy sources, especially wind, also is expected to grow significantly. In the IEO2011 Reference case, electricity generation from wind plants in China grows by 14.2 percent per year, from 12 billion kilowatthours in 2008 to 447 billion kilowatthours in 2035. In addition, government policies in China and India are encouraging the growth of solar generation. Under its "Golden Sun" program, announced in July 2009, the Chinese Ministry of Finance plans to subsidize 50 percent of the construction costs for grid-connected solar plants [282]. India's National Solar Mission, launched in November 2009, aims to have 20 gigawatts of installed solar capacity (both PV and solar thermal) by 2020, 100 gigawatts by 2030, and 200 gigawatts by 2050 [283]. India's targets have been discounted in the *IEO2011* Reference case because of the substantial uncertainty about the future of government-provided financial incentives [284]. However, the policies do support robust growth rates in solar generation for China and India, at 22 percent per year and 28 percent per year, respectively, in the Reference case.

Measuring the growth of China's wind capacity has proven difficult as the number of wind farms rapidly expands. According to the Chinese Renewable Energy Industry Association (CREIA), the country had 41.8 gigawatts of installed wind capacity at the end of 2010 [285]. The National Energy Administration and the Chinese Electricity Council, however, report only 31.1 gigawatts of wind capacity connected to the electricity grid at the end of 2010. The discrepancy between the two figures is a result of the inability of some local grids to absorb wind-generated electricity, a lack of long-distance transmission lines [286], and policies (now superseded) that encouraged construction of wind capacity instead of generation of electricity. The *IEO2011* Reference case assumes that China had 31.1 gigawatts of wind capacity installed at the end of 2010.

Although geothermal energy is a small contributor to non-OECD Asia's total electricity generation, it plays an important role in the Philippines and Indonesia. With the second-largest amount of installed geothermal capacity in the world, the Philippines generated almost 16 percent of its total electricity from geothermal sources in 2010 [287]. Indonesia, with the world's third-largest installed geothermal capacity, plans to have 3.9 gigawatts of capacity installed by 2014 [288] and 9.5 gigawatts by 2025 [289]. However, those goals are discounted in the Reference case in view of the long lead times and high exploration costs associated with geothermal energy.

### Middle East

Electricity generation in the Middle East region grows by 2.5 percent per year in the Reference case, from 0.7 trillion kilowatthours in 2008 to 1.4 trillion kilowatthours in 2035. The region's young and rapidly growing population, along with a strong increase in national income, is expected to result in rapid growth in demand for electric power. Iran, Saudi Arabia, and the United Arab Emirates (UAE) account for two-thirds of the region's demand for electricity, and demand has increased sharply over the past several years in each of those countries. From 2000 to 2008, Iran's net generation increased by an average of 7.5 percent per year, Saudi Arabia's by 6.2 percent per year, and the UAE's by 10.1 percent per year.

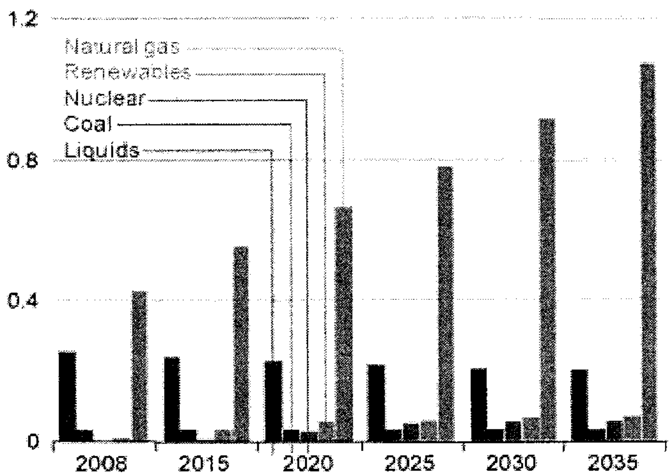
The Middle East depends on natural gas and petroleum liquid fuels to generate most of its electricity and is projected to continue that reliance through 2035, although liquids-fired generation declines over the projection period and thus loses market share to natural-gas-fired generation (Figure 83). In 2008, natural gas supplied 59 percent of electricity generation in the Middle East and liquid fuels 35 percent. In 2035, the natural gas share is projected to be 75 percent and the liquid fuels share 14 percent. There has been a concerted effort by many of the petroleum exporters in the region to develop their natural gas resources for use in domestic power generation. Petroleum is a valuable export commodity for many nations in the Middle East, and there is growing interest in the use of domestic natural gas for electricity generation in order to make more oil assets available for export.

figure data

Other energy sources make only minor contributions to electricity supply in the Middle East. Israel is the only country in the region that uses significant amounts of coal to generate electric power [290], and Iran and the UAE are the only ones projected to add nuclear capacity. Iran's 1,000-megawatt Bushehr reactor is scheduled to begin operating in 2011, although it has faced repeated delays, the latest being the detection of metal particles in the nuclear fuel rods, with the result that the fuel had to be unloaded and tested for possible contamination [291]. In December 2009, the Emirates Nuclear Energy Corporation (ENEC) in the UAE selected a South Korean consortium to build four nuclear reactors, with construction planned to begin in 2012 [292]. ENEC filed construction license applications for the first two units in December 2010, and it plans to have all four units operational by 2020 [293].

In addition to Iran and the UAE, several other Middle Eastern nations have announced intentions in recent years to pursue nuclear power programs. In 2010, the six-nation Gulf Cooperation Council[31] entered into a contract with U.S.-based Lightbridge Corporation to assess regional cooperation in the development of nuclear power and desalination programs [294]. Jordan also has announced its intention to add nuclear capacity [295], and in 2010 Kuwait's National Nuclear Energy

Figure 83. Middle East net electricity generation by fuel, 2008-2035
(trillion kilowatthours)




Committee announced plans to build four reactors by 2022 [296]. Even given the considerable interest in nuclear power in the region, however, given the economic and political issues and long lead times usually associated with beginning a nuclear program, the only reactors projected to be built in the Middle East in the *IEO2011* Reference case are in Iran and the UAE.

Several Middle Eastern countries recently have expressed some interest in increasing coal-fired generation in response to concerns about diversifying the electricity fuel mix and meeting the region's fast-paced growth in electricity demand. For example, Oman announced in 2008 that it would construct the Persian Gulf's first coal-fired power plant at Duqm [297]. According to the plan, the 1-gigawatt plant will be fully operational by 2016, powering a water desalinization facility [298]. The UAE, Saudi Arabia, and Bahrain also have considered building coal-fired capacity [299].

Although there is little economic incentive for countries in the Middle East to increase their use of renewable energy sources (the renewable share of the region's total electricity generation increases from only 1 percent in 2008 to 5 percent in 2035 in the Reference case), there have been some recent developments in renewable energy use in the region. Iran, which generated 10 percent of its electricity from hydropower in 2010, is adding approximately 4 gigawatts of new hydroelectric capacity, even after the droughts of 2007 and 2008 reduced available hydroelectric generation by nearly 75 percent [300]. Although development of Abu Dhabi's Masdar City project has been slowed by the current global economic environment [301], the government still plans to meet its 2020 goal of producing 7 percent of its energy from renewable sources. Solar power is expected to meet the vast majority of that goal, including two 100-megawatt solar power plants that Masdar Power plans to build [302].

## Africa

Figure 84. Net electricity generation in Africa by fuel, 2008-2035
(trillion kilowatthours)

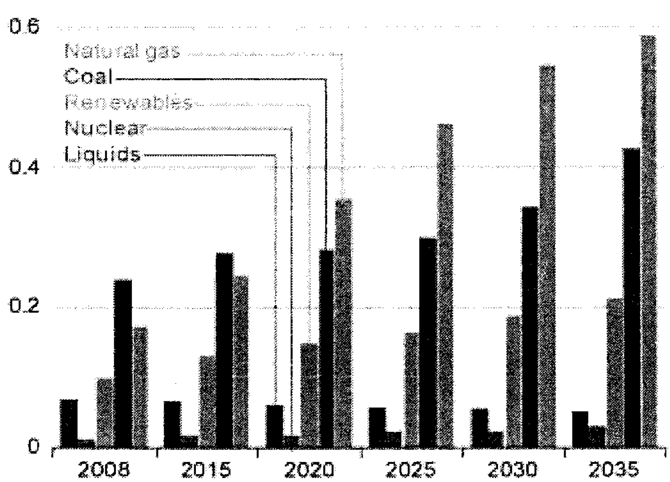



figure data

Demand for electricity in Africa grows at an average annual rate of 3.0 percent in the *IEO2011* Reference case. Fossil-fuel-fired generation supplied 81 percent of the region's total electricity in 2008, and reliance on fossil fuels is expected to continue through 2035. Coal-fired power plants, which were the region's largest source of electricity in 2008, accounting for 41 percent of total generation, provide a 33-percent share in 2035; and natural-gas-fired generation expands strongly, from 29 percent of the total in 2008 to 45 percent in 2035 (Figure 84).

At present, South Africa's two nuclear reactors are the only commercial reactors operating in the region, accounting for about 2 percent of Africa's total electricity generation. Although the construction of a new Pebble Bed Modular Reactor in South Africa has been canceled, the South African government's Integrated Electricity Resource Plan calls for another 9.6 gigawatts of nuclear capacity to be built by 2030 [303]. In addition, in May 2009, Egypt's government awarded a contract to Worley Parsons for the construction of a 1,200-megawatt nuclear power plant. Although original plans were for one unit, current plans call for four units, with the first plant to be operational in 2019 and the others by 2025 [304]. In the Reference case, 2.3 gigawatts of net nuclear capacity becomes operational in Africa over the 2008-2035 period, although only South Africa is expected to complete construction of any reactors. The nuclear share of the region's total generation remains at 2 percent in 2035.

Generation from hydropower and other marketed renewable energy sources is expected to grow relatively slowly in Africa. Plans for several hydroelectric projects in the region have been advanced recently, and they may help to boost supplies of marketed renewable energy in the mid-term. Several (although not all) of the announced projects are expected to be completed by 2035, allowing the region's consumption of marketed renewable energy to grow by 2.9 percent per year from 2008 to 2035. For example, Ethiopia finished work on two hydroelectric facilities in 2009: the 300-megawatt Takeze power station and the 420-megawatt Gilgel Gibe II [305]. A third plant, the 460-megawatt Tana Beles, was completed in 2010 [306].

## Central and South America

Electricity generation in Central and South America increases by 2.4 percent per year in the *IEO2011* Reference case, from 1.0 trillion kilowatthours in 2008 to 1.9 trillion kilowatthours in 2035. The fuel mix for electricity generation in Central and South America is dominated by hydroelectric power, which accounted for nearly two-thirds of the region's total net electricity generation in 2008. Of the top five electricity-generating countries in the region, three—Brazil, Venezuela, Paraguay—generate more than 70 percent of their total electricity from hydropower.

Figure 85. Net electricity generation in Brazil by fuel, 2008-2035

(trillion kilowatthours)

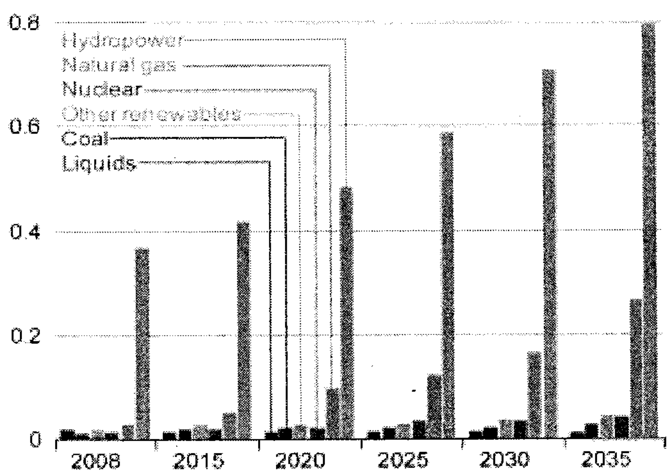



figure data

In Brazil, the region's largest economy, hydropower provided more than 80 percent of electricity generation in 2008 (Figure 85). The country has been trying to diversify its electricity generation fuel mix away from hydroelectric power because of the risk of power shortages during times of severe drought. In the Brazilian National Energy Plan for 2010-2019, the government set a goal to build 63 gigawatts of installed capacity, with nonhydroelectric capacity making up the majority of additions [307]. To help achieve that target, the government has announced plans to increase nuclear power capacity, beginning with the completion of the long-idled 1.3-gigawatt Angra-3 project [308]. Construction resumed in June 2010, and Angra-3 is expected to be operational at the end of 2015 [309]. Brazil also has plans to construct four new 1-gigawatt nuclear plants beginning in 2015. In the *IEO2011* Reference case, the Angra-3 project is completed by 2015, and three more planned nuclear projects are completed by 2035.

In the past, the Brazilian government has tried (with relatively little success) to attract substantial investment in natural-gas-fired power plants. Its lack of success has been attributed mainly to the higher costs of natural-gas-fired generation relative to hydroelectric power, and to concerns about the security of natural gas supplies. Brazil has relied on imported Bolivian natural gas for much of its supply, but concerns about the impact of Bolivia's nationalization of its energy sector on foreign investment in the country's natural gas production has led Brazil to look toward LNG imports for secure supplies. Brazil has invested strongly in its LNG infrastructure, and its third LNG regasification plant is scheduled for completion in 2013 [310].

With Brazil diversifying its natural gas supplies, substantially increasing domestic production, and resolving to reduce the hydroelectric share of generation, natural gas is projected to be its fastest-growing source of electricity, increasing by 8.7 percent per year on average from 2008 to 2035.

Brazil still has plans to continue expanding its hydroelectric generation over the projection period, including the construction of two plants on the Rio Madeira in Rondonia—the 3.2-gigawatt Santo Antonio and the 3.3-gigawatt Jirau hydroelectric facilities. The two plants, with completion dates scheduled for 2012-2013, are expected to help Brazil meet electricity demand in the mid-term [311]. In the long term, electricity demand could be met in part by the proposed 11.2-gigawatt Belo Monte dam, which was given approval for construction in April 2010 [312]. Each of the three projects could, however, be subject to further delay as a result of legal challenges.

Brazil is also interested in increasing the use of other, nonhydroelectric renewable resources in the future—notably, wind. In December 2009, Brazil held its first supply tender exclusively for wind farms. At the event, 1.8 gigawatts of capacity were purchased, for development by mid-2012 [313]. The first signs of wind development are now taking place, with a purchase contract already signed for the 90-megawatt Brotas wind farm, which is scheduled for completion in 2011 [314]. In the *IEO2011* Reference case, wind power generation in Brazil grows by 10.8 percent per year, from 530 million kilowatthours in 2008 to 8,508 million kilowatthours in 2035. Despite that robust growth, however, wind remains a modest component of Brazil's renewable energy mix in the Reference case, as compared with the projected growth in hydroelectric generation to 792 billion kilowatthours in 2035.

Figure 86. Other Central and South America net electricity generation by fuel, 2008-2035
(trillion kilowatthours)

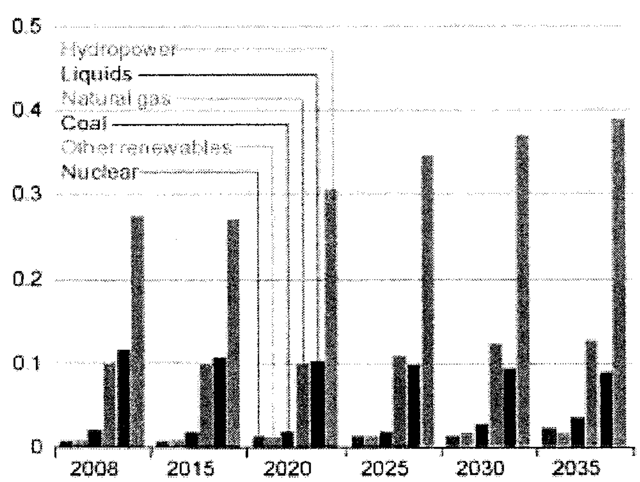



figure data

In the *IEO2011* Reference case, natural-gas-fired generation and hydroelectric generation are expected to dominate the electric power sector in Central and South America (excluding Brazil), increasing from 73 percent of total electricity generation in 2008 to 79 percent in 2035 (Figure 86). However, some countries in the region have a more diverse fuel mix. Argentina, for example, generated 6 percent of its electricity from its two nuclear power plants in 2008. Although construction of a third reactor, Atucha 2, was suspended in 1994, the 692-megawatt facility is scheduled to be completed by the end of 2011 [315].

Many countries in Central and South America are continuing their attempts to increase the role of natural gas in the electricity mix to prevent blackouts, caused by a combination of surging electricity demand and droughts that decrease generation from hydroelectric sources. Argentina, which experienced repeated power outages from December 20 through 31 in the summer of 2010, continues to increase LNG imports. The Argentine government has announced plans to build an import terminal outside Buenos Aires by 2012 and has signed a deal to import up to 706 million cubic feet of LNG from Qatar through another new terminal in Rio Negro province [316]. Venezuela has also committed to increasing its use of natural gas for electricity generation to both reduce the nation's heavy reliance on hydroelectricity and to meet fast-paced growth in electricity demand. At present, hydroelectricity accounts for around 63 percent of Venezuela's total installed generating capacity. In 2010, an extremely hot and dry summer reduced available hydroelectric generation so much that the country was forced to ration electricity [317]. The rationing program was suspended on July 30, 2010 as rainfall returned reservoir levels at the Guri hydroelectric plant approached more normal levels. However, despite the government's aggressive investment in power sector infrastructure improvements over the past two years, electricity demand has continued to outpace the growth in generating capacity [318]. Venezuela once again began to experience widespread power outages beginning in March 2011 and in June the government announced it would reinstate electricity rationing in an attempt to reduce electricity demand in addition to continuing to invest in generating capacity increases.

DOE/EIA-0560(98)

# Natural Gas 1998

## Issues and Trends

April 1999

**Energy Information Administration**
Office of Oil and Gas
U.S. Department of Energy
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# Preface

*Natural Gas 1998: Issues and Trends* provides a summary of the latest data and information relating to the U.S. natural gas industry, including prices, production, transmission, consumption, and the financial and environmental aspects of the industry. The report consists of seven chapters and five appendices.

Chapter 1 presents a summary of various data trends and key issues in today's natural gas industry and examines some of the emerging trends. Chapters 2 through 7 focus on specific areas or segments of the industry, highlighting some of the issues associated with the impact of natural gas operations on the environment.

Unless otherwise stated, historical data on natural gas production, consumption, and price through 1997 are from the Energy Information Administration (EIA) publication, *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, November 1998). Similar annual data for 1998 and monthly data for 1997 and 1998 are from EIA, *Natural Gas Monthly* (*NGM*), DOE/EIA-0130 (99/02) (Washington, DC, February 1999).

*Natural Gas 1998: Issues and Trends* was prepared by the Energy Information Administration, Office of Oil and Gas, Kenneth A. Vagts, Director (202/586-6401). General information concerning this report may be obtained from Joan E. Heinkel, Director of the Natural Gas Division (202/586-4680). Questions on specific sections of the report may be addressed to the following analysts:

- Chapter 1. "Overview," James Tobin (202/586-4835).
- Chapter 2. "Natural Gas and the Environment," Robert F. King (202/586-4787).
- Chapter 3. "Future Supply Potential of Natural Gas Hydrates," David F. Morehouse (202/586-4853).
- Chapter 4. "Offshore Development and Production," William A. Trapmann (202/586-6408).
- Chapter 5. "Natural Gas Pipeline Network: Changing and Growing," James Tobin (202/586-4835).
- Chapter 6. "Contracting Shifts in the Pipeline Transportation Market," Barbara Mariner-Volpe (202/586-5878).
- Chapter 7. "Mergers and Other Corporate Combinations in the Natural Gas Industry," William A. Trapmann (202/586-6408).

The overall scope and content of the report was supervised by James Tobin. Significant analytical contributions were made by the following individuals:

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Michael J. Elias—Chapter 1

William R. Keene—Chapter 7

James P. O'Sullivan—Chapter 6

Philip Shambaugh—Chapters 2 and 6

Michael J. Tita—Chapters 1 and 6

James Thompson—Chapter 1

James Todaro—Chapters 1 and 2

Lillian (Willie) Young—Chapter 1.

Editorial support was provided by Willie Young. Desktop publishing support was provided by Margareta Bennett.

# Contents

# Tables



# Figures

Figures 1 through 19 (Chapter 1) are composed of multiple illustrations. Below each figure title for Chapter 1, there is a list of subtitles describing each illustration. The subtitles are listed in the order in which the illustrations appear in the figure, from left to right moving down the page. The remaining figures (20 through 57) are single illustrations with no subtitles.

# 2. Natural Gas and the Environment

Currently, natural gas represents 24 percent of the energy consumed in the United States. The Energy Information Administration (EIA) *Annual Energy Outlook 1999* projects that this figure will increase to about 28 percent by 2020 under the reference case as consumption of natural gas is projected to increase to 32.3 trillion cubic feet. In addition, a recent EIA Service Report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, indicates that the use of natural gas could be even 6 to 10 percent higher in 2020 if the United States adopts the Kyoto Protocol's requirement to reduce carbon emissions by 7 percent from their 1990 levels by the 2008–2012 time period, without other changes in laws, regulations, and policies. These increases are expected because emissions of greenhouse gases are much lower with the consumption of natural gas relative to other fossil fuel consumption. For instance:

- Natural gas, when burned, emits lower quantities of greenhouse gases and criteria pollutants per unit of energy produced than do other fossil fuels. This occurs in part because natural gas is more easily fully combusted, and in part because natural gas contains fewer impurities than any other fossil fuel. For example, U.S. coal contains 1.6 percent sulfur (a consumption-weighted national average) by weight. The oil burned at electric utility power plants ranges from 0.5 to 1.4 percent sulfur. Diesel fuel has less than 0.05 percent, while the current national average for motor gasoline is 0.034 percent sulfur. Comparatively, natural gas at the burner tip has less than 0.0005 percent sulfur compounds.

- The amount of carbon dioxide produced for an equivalent amount of heat production varies substantially among the fossil fuels, with natural gas producing the least. On a carbon-equivalent basis, energy-related carbon dioxide emissions accounted for 83.8 percent of U.S. anthropogenic greenhouse gas emissions in 1997. For the major fossil fuels, the amounts of carbon dioxide produced for each billion Btu of heat energy extracted are: 208,000 pounds for coal, 164,000 pounds for petroleum products, and 117,000 pounds for natural gas.

Other aspects of the development and use of natural gas need to be considered as well in looking at the environmental consequences related to natural gas. For example:

- The major constituent of natural gas, methane, also directly contributes to the greenhouse effect through venting or leaking of natural gas into the atmosphere. This is because methane is 21 times as effective in trapping heat as is carbon dioxide. Although methane emissions amount to only 0.5 percent of U.S. emissions of carbon dioxide, they account for about 10 percent of the greenhouse effect of U.S. emissions.

- A major transportation-related environmental advantage of natural gas is that it is not a source of toxic spills. But, because there are about 300,000 miles of high-pressure transmission pipelines in the United States and its offshore areas, there are corollary impacts. For instance, the construction right-of-way on land commonly requires a width of 75 to 100 feet along the length of the pipeline; this is the area disturbed by trenching, soil storage, pipe storage, vehicle movement, etc. This area represents between 9.1 and 12.1 acres per mile of pipe which is, or has been, subject to intrusion.

Natural gas is seen by many as an important fuel in initiatives to address environmental concerns. Although natural gas is the most benign of the fossil fuels in terms of air pollution, it is less so than nonfossil-based energy sources such as renewables or nuclear power. However, because of its lower costs, greater resources, and existing infrastructure, natural gas is projected to increase its share of energy consumption relative to all other fuels, fossil and nonfossil, under current laws and regulations.

The vast majority of U.S. energy use comes from the combustion of fossil hydrocarbon fuels. This unavoidably results in a degree of air, land, and water pollution, and the production of greenhouse gases that might contribute to global warming and certain public health risks. To address these health and environmental concerns, the United States has many laws and regulations in place that are designed to control and/or reduce pollution. In the United States, natural gas use is projected to increase nearly 50 percent by 2020.[1] This is because North American natural gas resources are considered both plentiful and secure, are expected to be competitively priced, and their increased use can be effective in reducing the emission of pollutants.

While the use of natural gas does have environmental consequences, it is attractive because it is relatively clean-burning. This chapter discusses many environmental aspects related to the use of natural gas, including the environmental impact of natural gas relative to other fossil fuels and some of the potential applications for increased use of natural gas. On the other hand, the venting or leaking of natural gas into the atmosphere can have a significant effect with respect to greenhouse gases because methane, the principal component of natural gas, is much more effective in trapping these gases than carbon dioxide. The exploration, production, and transmission of natural gas, as well, can have adverse effects on the environment. This chapter addresses the level and extent of some of these impacts on the environment.

## Air Pollutants and Greenhouse Gases

The Earth's atmosphere is a mixture primarily of the gases nitrogen and oxygen, totaling 99 percent; nearly 1 percent water; and very small amounts of other gases and substances, some of which are chemically reactive. With the exception of oxygen, nitrogen, water, and the inert gases, all constituents of air may be a source of concern owing either to their potential health effects on humans, animals, and plants, or to their influence on the climate.

As mandated by The Clean Air Act (CAA), which was last amended in 1990, the Environmental Protection Agency (EPA) regulates "criteria pollutants" that are considered harmful to the environment and public health:

- **Gases**. The gaseous criteria pollutants are carbon monoxide, nitrogen oxides, volatile organic compounds,[2] and sulfur dioxide (Figure 20). These are reactive gases that in the presence of sunlight contribute to the formation of ground level ozone, smog, and acid rain.

- **Particulates**. The nongaseous criteria pollutant particulate matter consists of metals and substances such as pollen, dust, yeast, mold, very tiny organisms such as mites and aerosolized liquids, and larger particles such as soot from wood fires or diesel fuel ignition.

- **Air Toxics.** The CAA identifies 188 substances as air toxics or hazardous air pollutants, with lead being the only one that is currently classified as a criteria pollutant and thus regulated. Air toxic pollutants are more acute biological hazards than most particulate or criteria pollutants but are much smaller in volume. Procedures are now underway to regulate other air toxics under the CAA.

The greenhouse gases are water vapor, carbon dioxide, methane, nitrous oxide, and a host of engineered chemicals, such as chlorofluorocarbons (Figure 21). These gases regulate the Earth's temperature. When the natural balance of the atmosphere is disturbed, particularly by an increase or decrease in the greenhouse gases, the Earth's climate could be affected.

The combustion of fossil fuels produces 84 percent of U.S. anthropogenic (created by humans) greenhouse emissions.[3] When wood burning is included, these fuels produce 95 percent of the nitrogen oxides, 94 percent of the carbon monoxide, and 93 percent of the sulfur dioxide criteria pollutants (Figure 20). Most of these emissions are released into the atmosphere as a result of fossil fuel use in industrial boilers and power plants and in motor vehicles.

### Emissions from Burning Natural Gas

Natural gas is less chemically complex than other fuels, has fewer impurities, and its combustion accordingly results in less pollution. Natural gas consists primarily of methane (see box, p. 52). In the simplest case, complete combustive reaction of a molecule of pure methane (which comprises one carbon atom and four hydrogen atoms) with two molecules of pure oxygen produces a molecule of carbon dioxide gas, two molecules of water in vapor form, and heat.[4] In practice, however, the combustion process is never

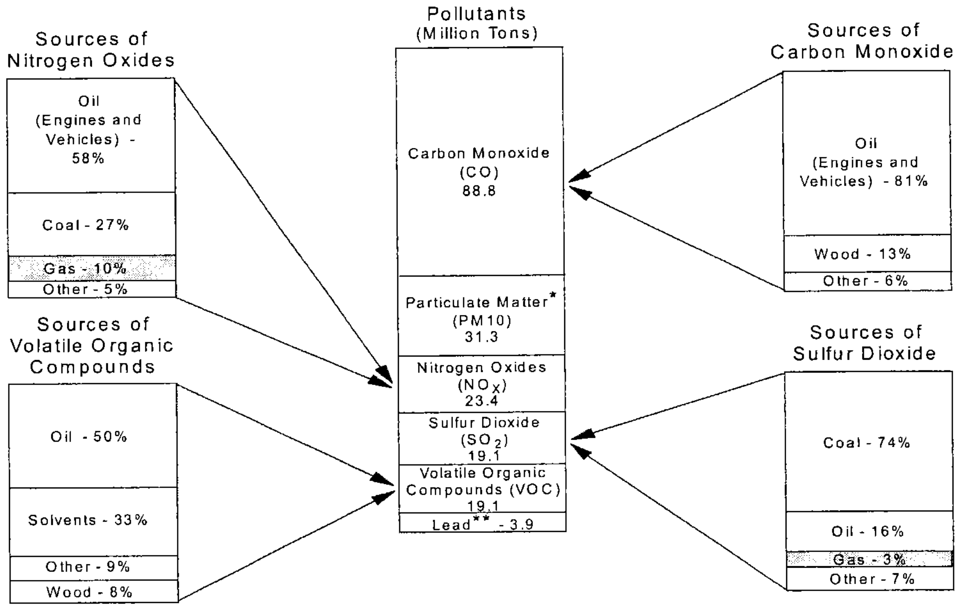
[1]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

[2]Note that methane, the principal ingredient in natural gas, is not classed as a volatile organic compound because it is not as chemically reactive as the other hydrocarbons, although it is a greenhouse gas.

[3]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998).

[4]As described by $CH_4 + 2\,O_2 \rightarrow CO_2 + 2\,H_2O$ + heat.

**Figure 20. U.S. Criteria Pollutants and Their Major Sources, 1996**

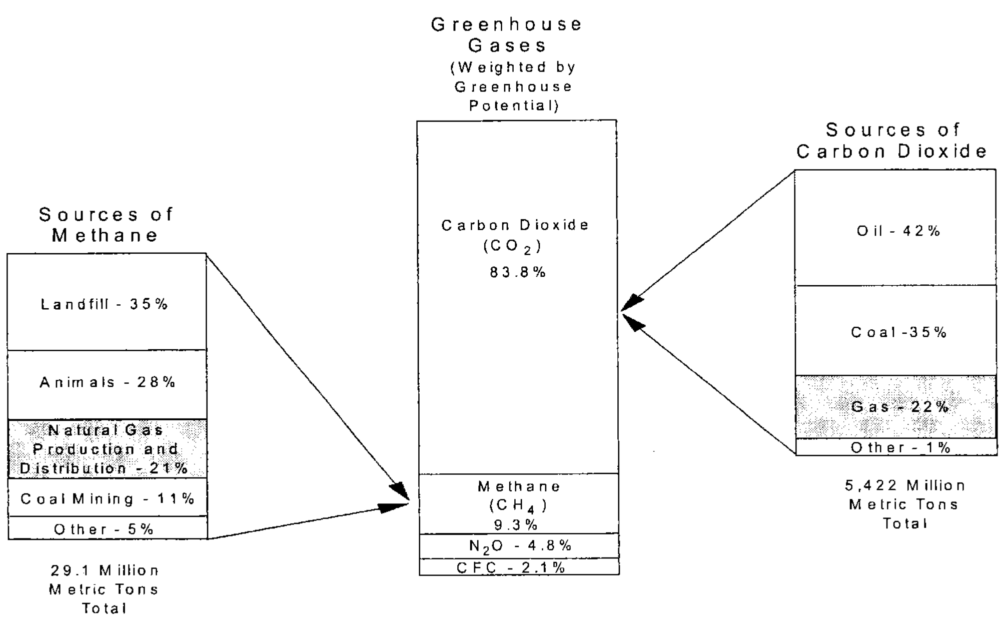



*Wood and other fuels account for only 9 percent of particulate matter.

**Oil accounts for 25 percent of lead and other fuels 2 percent.

Source: Energy Information Administration, Office of Oil and Gas, derived from: Environmental Protection Agency, National Air Pollutant Emission Trends 1990-1996, Appendix A (December 1997).

**Figure 21. U.S. Anthropogenic Greenhouse Gases and Their Sources, 1997**




$N_2O$ = Nitrous oxide. CFC = Chlorofluorocarbon.

Source: Energy Information Administration, Emissions of Greenhouse Gases in the United States 1997 (October 1998).

## Sources and Chemical Composition of Natural Gas

Natural gas is obtained principally from conventional crude oil and nonassociated gas reservoirs, and secondarily from coal beds, tight sandstones, and Devonian shales. Some is also produced from minor sources such as landfills. In the future, it may also be obtained from natural gas hydrate deposits located beneath the sea floor in deep water on the continental shelves or associated with thick subsurface permafrost zones in the Arctic.

Natural gas is a mixture of low molecular-weight aliphatic (straight chain) hydrocarbon compounds that are gases at surface pressure and temperature conditions. At the pressure and temperature conditions of the source reservoir, it may occur as free gas (bubbles) or be dissolved in either crude oil or brine. While the primary constituent of natural gas is methane ($CH_4$), it may contain smaller amounts of other hydrocarbons, such as ethane ($C_2H_6$) and various isomers of propane ($C_3H_8$), butane ($C_4H_{10}$), and the pentanes ($C_5H_{12}$), as well as trace amounts of heavier hydrocarbons. Nonhydrocarbon gases, such as carbon dioxide ($CO_2$), helium (He), hydrogen sulfide ($H_2S$), nitrogen ($N_2$), and water vapor ($H_2O$), may also be present in any proportion to the total hydrocarbon content.

Pipeline-quality natural gas contains at least 80 percent methane and has a minimum heat content of 870 Btu per standard cubic foot. Most pipeline natural gas significantly exceeds both minimum specifications. Since natural gas has by far the lowest energy density of the common hydrocarbon fuels, by volume (not weight) much more of it must be used to provide a given amount of energy. Natural gas is also much less physically dense, weighing about half as much (55 percent) as the same volume of dry air at the same pressure. It is consequently buoyant in air, in which it is also combustible at concentrations ranging from 5 percent to 15 percent by volume.

that perfect as it takes place in air rather than in pure oxygen, resulting in some pollutants.[5]

The reaction products include particulate carbon, carbon monoxide, and nitrogen oxides, in addition to carbon dioxide, water vapor, and heat. Carbon monoxide, the nitrogen oxides, and particulate carbon are criteria pollutants (regulated emissions). The proportions of the reaction products are determined by the efficiency of combustion. For instance, when the air supply to a gas burner is not adequate, the produced levels of carbon monoxide and other pollutants are greater. This situation is, of course, similar to that of all other fossil hydrocarbon fuels—insufficient oxygen supply to the burner will inevitably result in incomplete combustion and the consequent production of carbon monoxide and other pollutants.

Since natural gas is never pure methane and air is not just oxygen and nitrogen, small amounts of additional pollutants are also generated during combustion of natural gas. For example, all fossil fuels contain sulfur; its removal from both oil and gas is a major part of the processing of these fuels prior to distribution. However, not all sulfur is removed during processing. When the fuel is burned, several oxides of sulfur are produced, consisting primarily of sulfur dioxide, some other sulfur-bearing acids, and traces of many other sulfur compounds depending on what other trace compounds are present in the fuel. Additionally, since natural gas is both colorless and odorless, sulfur-bearing odorants[6] are intentionally added to the gas stream by gas distributors so that residential consumers can smell a leak. Besides sulfur, natural gas can include other trace impurities and contaminants.[7]

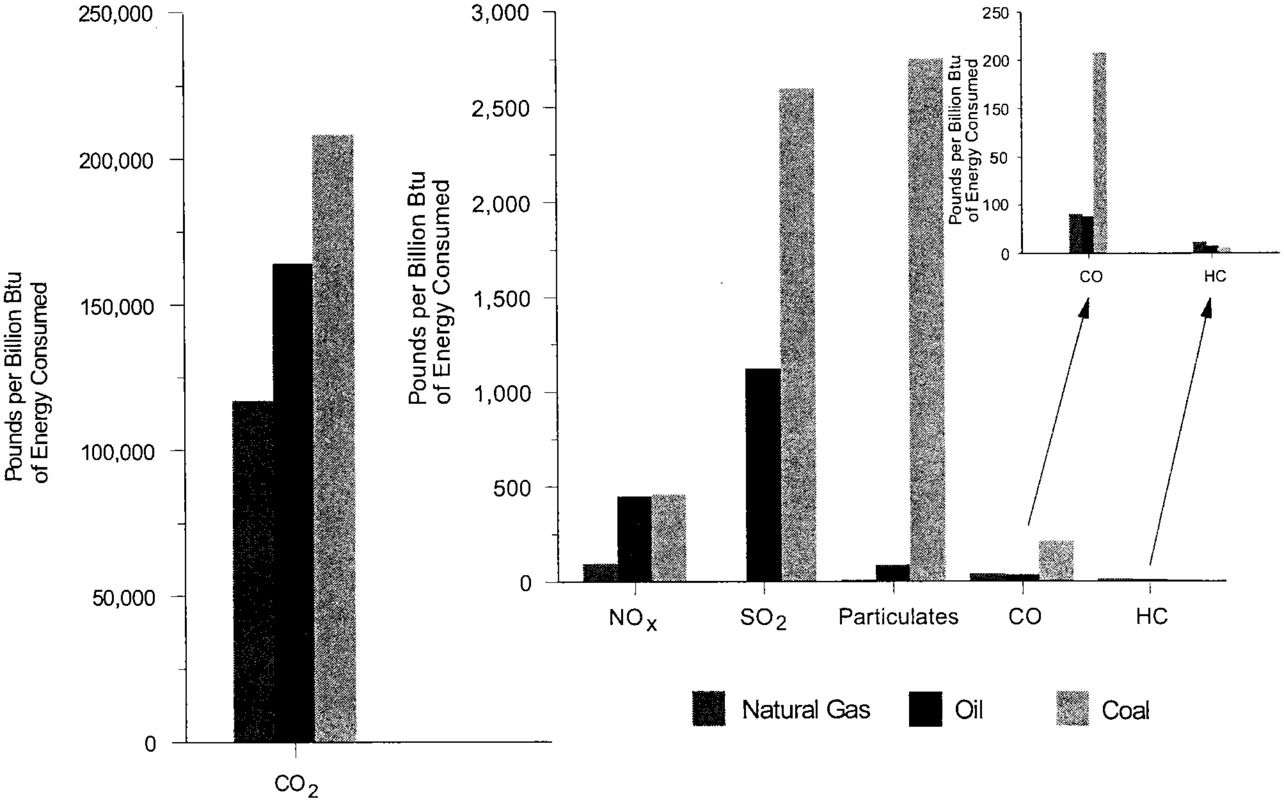
Yet the emittable pollutants resulting from combustion of natural gas are far fewer in volume and number than those from the combustion of any other fossil fuel (Figure 22). This occurs in part because natural gas is more easily fully combusted, and in part because natural gas has fewer impurities than other hydrocarbon fuels. For example, the amount of sulfur in natural gas is much less than that of

[5]Since the process takes place in air rather than pure oxygen, the practical result is more like: $CH_4 + O_2 + N_2 \rightarrow C + CO + CO_2 + N_2O + NO + NO_2 + H_2O + CH_4$ (unburned) + heat (exact proportions depend on the prevailing combustion conditions).

[6]These odorants are compounds such as dimethyl sulfide, tertiary butyl mercaptan, tetrahydrothiophene, and methyl mercaptan.

[7]Trace impurities can include radon, benzene, toluene, ethylbenzene, xylene, and organometallic compounds such as methyl mercury. The list of combustion byproducts can include fine particulate matter, polycyclic aromatic hydrocarbons, and volatile organic compounds including formaldehyde.

**Figure 22. Air Pollutant Emissions by Fuel Type**




$CO_2$ = Carbon dioxide. $No_x$ = Nitrogen oxides. $SO_2$ = Sulfur dioxide. CO = Carbon monoxide. HC = Hydrocarbon.
Note: Graphs should not be directly compared because vertical scales differ.
Source: Energy Information Administration (EIA) Office of Oil and Gas. **Carbon Monoxide:** derived from EIA, *Emissions of Greenhouse Gases in the United States 1997,* Table B1, p. 106. **Other Pollutants:** derived from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors,* Vol. 1 (1998). Based on conversion factors derived from EIA, *Cost and Quality of Fuels for Electric Utility Plants* (1996).

coal or oil. U.S. coals contain an average of 1.6 percent sulfur by weight,[8] and the oil burned at electric utility power plants ranges from 0.5 percent to 1.4 percent sulfur.[9] Diesel fuel has less than 0.05 percent sulfur by weight (or 500 parts per million (ppm)) and the current national average for motor gasoline is 340 ppm sulfur (includes California where the regulated statewide average is 30 ppm).[10] Comparatively, natural gas at the burner tip has less than 5 ppm of all sulfur compounds, typically comprising about 1 ppm hydrogen sulfide and less than 2 ppm of each sulfur-bearing odorant.[11]

### *Toxic and Particulate Emissions*

The combustion of natural gas also produces significantly lower quantities of other undesirable compounds,

[8]U.S. coals burned at Clean Air Act Phase I electric power plants contain an average of 0.3 percent sulfur for western coals and 2.5 percent for eastern coals, yielding a consumption-weighted national average of 1.6 percent sulfur by weight.

[9]Energy Information Administration, *Electric Power Annual, 1996,* Vol. 2, DOE/EIA-348(96) (Washington, DC, 1997), p. 41.

[10]Gerald Karey, "EPA leaves sulfur verdict for another day," *Platts Oilgram News,* 76/78 (April 24, 1998), p. 4.

[11]Washington Gas Light Company personnel stated that its system hydrogen sulfide ($H_2S$) levels are 1.8 parts per million (ppm) and the sulfur-bearing odorants are 2.0 ppm. Institute for Gas Technology tests of trace constituents in two intrastate pipeline samples and two Canadian interstate samples supplied by the Pacific Gas and Electric Company had less than 5 ppm total $H_2S$ (usually between 1 and 1.5 ppm). Sulfur content by contract for pipeline-quality natural gas varies from 0.25 grains to 1.0 grain per 100 standard cubic feet (1.9 ppm to 7.6 ppm), in many cases 0.25 grains or 1.9 ppm. Dr. John M. Campbell, Chapter 7, "Product Specifications," *Gas Conditioning and Processing,* Vol. 1 (Norman, OK, 1979).

particularly toxics, than those produced from combustion of petroleum products or coal. Toxic air pollutants are those compounds that are not specifically covered under other portions of the CAA (i.e., the criteria pollutants and particulate matter) and are typically carcinogens, reproductive toxics, and mutagens. The United States emits 2.7 billion pounds of toxics into the atmosphere each year. Motor vehicles are the primary source, followed by residential wood combustion. Section 112 of the CAA of 1990 lists 188 toxic compounds or groups as hazardous air pollutants (HAPs), including various compounds of mercury, arsenic, lead, nickel, and beryllium and also organic compounds, such as toluene, benzene, formaldehyde, chloroform, and phosgene, which are expected to be regulated soon. Presently, only lead is regulated.

The toxic compound benzene can be a component of both petroleum products and natural gas, but whereas it can comprise up to 1.5 percent by weight of motor gasoline, the levels in natural gas are considered insignificant and are not generally monitored by gas-processing plants and most pipeline companies.[12] As required by California Proposition 65, the Safe Drinking Water and Toxic Enforcement Act, gas pipeline companies that operate in California continuously monitor for toxic substances. These companies have found that the benzene and toluene content of the natural gas they carry varies by source and can range from less than 0.4 ppm to 6 ppm for interstate gas and up to 100 ppm for intrastate gas.[13] Depending on the efficiency of the combustion, some will be oxidized to carbon dioxide and water, some will pass through unburned, and some will be converted to other toxic compounds.

The particulates produced by natural gas combustion are usually less than 1 micrometer (micron) in diameter and are composed of low molecular-weight hydrocarbons that are not fully combusted.[14] Typically, combustion of the other fossil fuels produces greater volumes of larger and more complex particulates. In 1998, the Environmental Protection Agency set a new standard for very fine (less than 2.5 microns) particulates as an add-on to the existing regulation of suspended particulates that are 10 microns or larger, set in 1987.[15] Although power plants and diesel-powered trucks and buses are major emitters of particulate matter, the bulk of 10-micron-plus particulate matter emissions is composed of "fugitive" dust from roadways (58 percent) and combined sources of agricultural operations and wind erosion (30 percent).[16]

## Acid Rain and Smog Formation

Natural gas is not a significant contributor to acid rain formation. Acid rain is formed when sulfur dioxide and the nitrogen oxides chemically react with water vapor and oxidants in the presence of sunlight to produce various acidic compounds, such as sulfuric acid and nitric acid. Electric utility plants generate about 70 percent of $SO_2$ emissions and 30 percent of $NO_x$ emissions in the United States; motor vehicles are the second largest source of both. Natural gas is responsible for only 3 percent of sulfur dioxide and 10 percent of nitrogen oxides (Figure 20). Precipitation in the form of rain, snow, ice, and fog causes about half of these atmospheric acids to fall to the ground as "acid rain," while about half fall as dry particles and gases. Winds can blow the particles and compounds hundreds of miles from their source before they are deposited, and they and their sulfate and nitrate derivatives contribute to atmospheric haze prior to eventual deposition as acid rain. The dry particles that land on surfaces are also washed off by rain, increasing the acidity of runoff.

Natural gas use also is not much of a factor in smog formation. As opposed to petroleum products and coal, the combustion of natural gas results in relatively small production of smog-forming pollutants. The primary constituent of smog is ground-level ozone created by photochemical reactions in the near-surface atmosphere involving a combination of pollutants from many sources, including motor vehicle exhausts, volatile organic compounds such as paints and solvents, and smokestack emissions. The smog-forming pollutants literally cook in the air as they mix together and are acted on by heat and sunlight. The wind can blow smog-forming pollutants away

[12]Based on communications with personnel at the Gas Processors Association and the Columbia Gas Pipeline Company.

[13]Institute for Gas Technology test of trace constituents in two intrastate pipeline samples and two Canadian interstate samples supplied by the Pacific Gas and Electric Company.

[14]The aerosolized particulate matter resulting from combustion of fossil fuels is a mixture of solid particles and liquid droplets inclusive of soot, smoke, dust, ash, and condensing vapors.

[15]The larger particles are usually trapped in the upper respiratory tract, whereas those smaller than 10 microns can penetrate further into the respiratory system. The most infamous cases of extreme particulate matter pollution, in Donora, Pennsylvania, and in London, England, during the 1930s-1950s, killed thousands of people, and recent studies have indicated that a relatively small rise in 2.5-micron particulates causes a 5-percent rise in infant mortality and greater risk of heart disease. Michael Day, "Taken to Heart," *New Scientist* (May 9, 1998), p. 23.

[16]Environmental Protection Agency, *National Air Pollution Trends Update, 1970-1997*, EPA-454/E-98-007 (December 1998), Table A-5 "Particulate Matter (PM-10) Emissions."

from their sources while the reaction takes place, explaining why smog can be more severe miles away from the source of pollutants than at the source itself.

## Greenhouse Gases and Climate Change

The Earth's surface temperature is maintained at a habitable level through the action of certain atmospheric gases known as "greenhouse gases" that help trap the Sun's heat close to the Earth's surface. The main greenhouse gases are water vapor, carbon dioxide, methane, nitrous oxide, and several engineered chemicals, such as chlorofluorocarbons. Most greenhouse gases occur naturally, but concentrations of carbon dioxide and other greenhouse gases in the Earth's atmosphere have been increasing since the Industrial Revolution with the increased combustion of fossil fuels and increased agricultural operations. Of late there has been concern that if this increase continues unabated, the ultimate result could be that more heat would be trapped, adversely affecting Earth's climate. Consequently, governments worldwide are attempting to find some mechanisms for reducing emissions or increasing absorption of greenhouse gases.[17]

On a carbon-equivalent basis, 99 percent of anthropogenically-sourced carbon dioxide emissions in the United States is due to the burning of fossil hydrocarbon fuels, with 22 percent of this attributed to natural gas (Table 1). Carbon dioxide emissions accounted for 83.8 percent of U.S. greenhouse gas emissions in 1997. Between 1996 and 1997, total estimated U.S. carbon dioxide emissions increased by 1.5 percent (22.0 million metric tons) to about 1,501 million metric tons of carbon, representing an increase of about 145 million metric tons, or almost 10.7 percent over the 1990 emission level. The increase between 1996 and 1997 was the sixth consecutive one. Increasing reliance on coal for electricity generation is one of the driving forces behind the growth in carbon emissions in 1996 and 1997.

The major constituent of natural gas, methane, also directly contributes to the greenhouse effect. Its ability to trap heat in the atmosphere is estimated to be 21 times greater than that of carbon dioxide, so although methane emissions amount to only 0.5 percent of U.S. emissions of carbon dioxide, they account for about 10 percent of the greenhouse effect of U.S. emissions. In 1997, methane emissions from waste management operations (primarily landfills), at 10.4 million metric tons, and from agricultural operations, at 8.6 million metric tons, substantially exceeded those from the oil and gas industries combined, estimated to be 6.2 million metric tons.[18]

Water vapor is the most common greenhouse gas, at about 1 percent of the atmosphere by weight, followed by carbon dioxide at 0.04 percent and then methane, nitrous oxide, and manmade compounds such as the chlorofluorocarbons (CFCs). Each gas has a different residence time in the atmosphere, from about a decade for carbon dioxide to 120 years for nitrous oxide and up to 50,000 years for some of the CFCs. Water vapor is omnipresent and continually cycles into and out of the atmosphere. In estimating the effect of these greenhouse gases on climate, both the global warming potential (heat-trapping effectiveness relative to carbon dioxide) and the quantity of gas must be considered for each of the greenhouse gases.

Since human activity has minimal impact on the atmosphere's water vapor content, unlike the other greenhouse gases it is not addressed in the context of global warming prevention. The criteria pollutants specified in the CAA are reactive gases that, although they decay quickly, nevertheless promote reactions in the atmosphere yielding the greenhouse gas ozone. These gases indirectly affect global climate because they produce undesirable lower atmosphere ozone, as opposed to the desirable high-altitude ozone that shields Earth from most of the Sun's ultraviolet radiation. Carbon dioxide, on the other hand, directly contributes to the greenhouse effect; it presently represents 61 percent of the worldwide global warming potential of the atmosphere's greenhouse gases.

The United States is the largest producer of carbon dioxide among the countries of the world, both per capita (5.4 tons in 1996) and absolutely (Figure 23).[19] The amount of carbon dioxide produced for an equivalent amount of heat production substantially varies among the fossil fuels, with

[17]In December 1997, representatives from more than 160 countries met in Kyoto, Japan, to establish limits on greenhouse gas emissions for participating developed nations. The resulting Kyoto Protocol established annual emission targets for countries relative to their 1990 emission levels. The target for the United States is 7 percent below 1990 levels.

[18]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998), pp. 27 and 29.

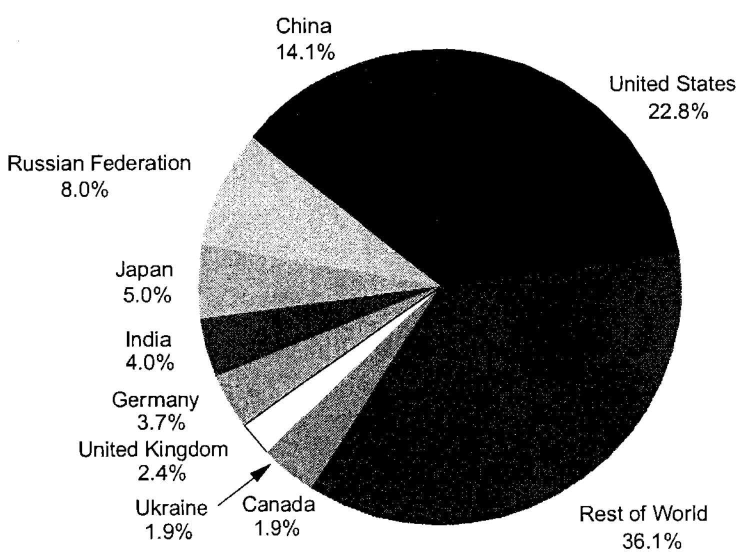
[19]U.S. Department of Energy, Oak Ridge National Laboratory, G. Marland and T. Broden, "Ranking of the World's Countries by 1995 Total $CO_2$ Emissions from Fossil Fuel Burning, Cement Production, and Gas Flaring,"<http://cdiac.esd.ornl.gov/trends/emis/top95.tot>.

**Table 1. U.S. Carbon Dioxide Emissions from Energy and Industry, 1990-1997**
(Million Metric Tons of Carbon)

| Fuel Type or Process | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | P1997 |
|---|---|---|---|---|---|---|---|---|
| **Natural Gas** | | | | | | | | |
| Consumption | 273.2 | 278.1 | 286.3 | 296.6 | 301.5 | 319.1 | 319.7 | 319.1 |
| Gas Flaring | 2.5 | 2.8 | 2.8 | 3.7 | 3.8 | 4.7 | 4.5 | 4.3 |
| $CO_2$ in Natural Gas | 3.6 | 3.7 | 3.9 | 4.1 | 4.3 | 4.2 | 4.5 | 4.6 |
| **Total** | **279.3** | **284.6** | **293.0** | **304.4** | **309.6** | **323.0** | **328.1** | **328.0** |
| **Other Energy** | | | | | | | | |
| Petroleum | 591.4 | 576.9 | 587.6 | 588.8 | 601.3 | 597.4 | 620.6 | 627.5 |
| Coal | 481.5 | 475.7 | 478.1 | 494.4 | 495.6 | 500.2 | 520.9 | 533.0 |
| Geothermal | 0.1 | 0.1 | 0.1 | 0.1 | * | * | * | * |
| **Total** | **1,073.0** | **1,052.7** | **1,065.8** | **1,083.3** | **1,096.9** | **1,097.6** | **1,141.5** | **1,160.5** |
| **Other Sources** | | | | | | | | |
| Cement Production | 8.9 | 8.7 | 8.8 | 9.3 | 9.8 | 9.9 | 9.9 | 10.1 |
| Other Industrial | 8.0 | 8.0 | 8.0 | 8.0 | 8.1 | 8.9 | 9.1 | 9.2 |
| Adjustments[a] | -13.2 | -13.2 | -14.9 | -11.3 | -10.7 | -11.2 | -9.8 | -7.1 |
| **Total** | **3.7** | **3.5** | **1.9** | **6.0** | **7.2** | **7.6** | **9.2** | **12.2** |
| **Total from Energy and Industry** | **1,355.9** | **1,340.8** | **1,360.6** | **1,393.6** | **1,413.8** | **1,428.1** | **1,478.8** | **1,500.8** |
| **Percent Natural Gas of Total** | **20.6** | **21.2** | **21.5** | **21.8** | **21.9** | **22.6** | **22.2** | **21.9** |

[a]Accounts for different methodologies in calculating emissions for U.S. territories.
*Less than 0.05 million metric tons.
P = Preliminary data.
Notes: Emission coefficients are annualized for coal, motor gasoline, liquefied petroleum gases, jet fuel, and crude oil. Includes emissions from bunker fuels. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Emissions of Greenhouse Gases in the United States 1997 (October 1998).

**Figure 23. Carbon Dioxide Emission Share by Country, 1995**




Total 1995 emissions = 6,173 million metric tons of carbon

Note: Sum of percentages does not equal 100 because of independent rounding.
Source: U.S. Department of Energy, Oak Ridge National Laboratory, G. Marland, T. Broden, "Ranking of the World's Countries by 1995 Total CO2 Emissions from Fossil Fuel Burning, Cement Production, and Gas Flaring," <http://cdiac.esd.ornl.gov/trends/emis/top95.tot>.

natural gas producing the least. For the major fossil fuels, the amounts of carbon dioxide produced for each billion Btu of heat energy extracted are: 208,000 pounds for coal, 164,000 pounds for petroleum products, and 117,000 pounds for natural gas (Table 2).

# Effect of Greater Use of Natural Gas

## Electric Power Generation

Projections of increased use of natural gas center principally on the increased use of natural gas in electric generation. For example, the *Annual Energy Outlook 1999* reference case projects natural gas consumption to rise by 10.3 trillion cubic feet (Tcf) from 1997 to 2020. Of this increase, 56 percent (5.8 Tcf) is expected to come as a result of increased use of natural gas for electricity generation. A recent Energy Information Administration (EIA) Service Report (prepared at the request of the House of Representatives Science Committee assuming no changes in domestic policy) analyzed the consequences of U.S. implementation of the Kyoto Protocol. In the carbon reduction cases cited in this report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*,[20] power plant use of natural gas (excluding industrial cogeneration) could increase to between 8 and 12 Tcf in 2010 and 12 to 15 Tcf in 2020. This growth is expected to develop as many of the new generating units brought on line are gas-fired. Some repowering of existing units may be undertaken as well.

Since electricity generation is the major source of U.S. sulfur dioxide ($SO_2$) and carbon dioxide ($CO_2$) emissions,[21] as well as a major source of all other air pollutants excepting the chlorinated fluorocarbons, substitution of natural gas for other fossil fuels by utilities and nonutility generators would have a sizable impact on emission levels. However, if increased natural gas generation were to replace nuclear power or delay the commercialization of renewable-powered generation, this would represent a negative impact on emission levels.

In 1997, there were 10,454 electric utility generating units in the United States, with a total net summer generation capacity of 712 gigawatts.[22] Of that capacity, 19 percent listed natural gas as the primary fuel and 27 percent listed it as either the primary or secondary fuel. But natural gas was actually used to generate only 9.1 percent of the electricity generated by electric utilities in 1997, down 1.2 percent from the 1995 value of 10.3 percent and one of the lowest proportions in the past 10 years. Coal was listed as the primary fuel source for almost 43 percent of the utility generating capacity and as a secondary source for only about 0.5 percent. But in 1997, it was the fuel used for 57.3 percent of net generation from electric utilities, up from 55.3 percent in 1995 and 56.3 percent in 1996.

A utility typically has a base-load generating capacity that is essentially continuously on line and capable of satisfying most or all of the minimum service-area load. The base-load capacity is supplemented by intermediate-load generation and peak-load generation capacities, which are used to meet the seasonal and short-term fluctuating demands above base load; reserve or standby units are also maintained to handle outages or emergencies. The majority of non-nuclear base-load units are coal-fired, yet many utilities have gas turbines, which are primarily used as peak-load generators.

Once the initial cost of a generating unit is paid for, fuel cost per unit of energy produced controls how electricity is generated. In 1997, the cost at steam-electric utility plants per million Btu for coal was less than half that for natural gas, $1.27 versus $2.76, and petroleum was even higher at $2.88.[23] The per Btu natural gas cost to utilities increased by over one-third from 1995 to 1997, while the per Btu coal cost continued a 15-year decline, contributing to the decreased market share for natural gas. However, new technologies creating higher efficiency natural gas electric

[20]Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), p. 76. This Service Report was requested by the U.S. House of Representatives Science Committee to provide information on the costs of the Kyoto Protocol without other changes in laws and regulations. The report relied on assumptions provided by the Committee.

[21]In 1996, electric utilities accounted for 12,604 thousand short tons of sulfur dioxide emissions out of a total of 19,113 thousand short tons (Environmental Protection Agency, *National Air Pollutant Emission Trends, 1990-1996*, EPA-454R-97-011 (December 1997), Table 2-1, p. 2-4); and for 532.4 million metric tons of carbon as carbon dioxide, exceeding the 482.9 and 473.1 million metric tons from the industrial and transportation sectors, respectively (Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (October 1998), Table 7, p. 21).

[22]Excludes nonutility generators. Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998). Nonutility generators totaled 78 gigawatts of capacity in 1997, with 42 percent utilizing natural gas. Energy Information Administration, *Electric Power Annual 1997*, Vol. II, DOE/EIA-348(97) (Washington, DC, July 1998), Table 54.

[23]Energy Information Administration, *Electric Power Annual 1997*, Vol. 1, DOE/EIA-348(97) (Washington DC, July 1998), Table 20, p. 37.

**Table 2. Pounds of Air Pollutants Produced per Billion Btu of Energy**

| Pollutant | Natural Gas | Oil | Coal |
|---|---|---|---|
| Carbon Dioxide | 117,000 | 164,000 | 208,000 |
| Carbon Monoxide | 40 | 33 | 208 |
| Nitrogen Oxides | 92 | 448 | 457 |
| Sulfur Dioxide | 0.6 | 1,122 | 2,591 |
| Particulates | 7.0 | 84 | 2,744 |
| Formaldehyde | 0.750 | 0.220 | 0.221 |
| Mercury | 0.000 | 0.007 | 0.016 |

Notes: No post combustion removal of pollutants. Bituminous coal burned in a spreader stoker is compared with No. 6 fuel oil burned in an oil-fired utility boiler and natural gas burned in uncontrolled residential gas burners. Conversion factors are: bituminous coal at 12,027 Btu per pound and 1.64 percent sulfur content; and No. 6 fuel oil at 6.287 million Btu per barrel and 1.03 percent sulfur content—derived from Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants (1996).

Source: Energy Information Administration (EIA), Office of Oil and Gas. **Carbon Monoxide:** derived from EIA, Emissions of Greenhouse Gases in the United States 1997, Table B1, p. 106. **Other Pollutants:** derived from Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Vol. 1 (1998).

generators can overcome the current price differential between the fuels.

The new power plants scheduled to come on line during the 10 years from 1998 through 2007 are 88 percent natural-gas-fired and only 5 percent coal-fired, but they will add only about 6 percent to total net generation capacity.[24] Thus, in order to make significant reductions in the volume of greenhouse gases and other pollutants produced by electricity generation, a significant amount of new unplanned gas-fired or renewable generation capacity would have to be built, or the existing generating equipment having natural gas as a fuel option would have to be utilized more and many of the existing coal plants would have to be repowered to burn gas.

The utilities have many supply-side options at their disposal to reduce or offset carbon dioxide emissions from power generation. These options include repowering of coal-based plants with natural gas, building new gas plants, extension of the life of existing nuclear plants, implementation of renewable electricity technologies, and improvement of the efficiency of existing generation, transmission, and distribution systems.

There are two principal conversion opportunities for utility power plants. The simplest and most capital-intensive approach is site repowering with an entirely new gas-turbine-based natural gas combined-cycle (NGCC) system. The more complex, less capital-intensive approach is steam turbine repowering where a new gas turbine and a heat recovery steam generator are integrated with the existing steam turbine and auxiliary equipment. This option can have lower capital costs if site redesign costs are low, but entails a higher operating cost because it is less efficient than total state-of-the-art repowering.

As of January 1, 1998, there are 20 repowering projects planned in nine States that will primarily convert current oil-fired facilities to natural gas or co-firing capability; most of the projects are driven by economics with a secondary impetus as a response to the emission reduction requirements of the Clean Air Act Amendments of 1990 (see box, p. 59).

Complete conversion may not be a practical goal for a number of plants without expansion of the transportation pipeline network. Most of the candidate plants are located in primary gas-consuming regions served by major trunk lines. It appears that converted plants may have sufficient access to firm transportation capacity on these systems during the heating and nonheating seasons, during which between 16 and 24 percent of average national system capability is available for firm transportation, respectively.[25] The ability of a plant to use firm transportation capacity for gas supply will depend on the location and specific load characteristics of the pipelines serving that plant. However, because of recent regulatory reforms, electric generation plants may no longer be required to use firm transportation to serve their supply needs. Under Federal

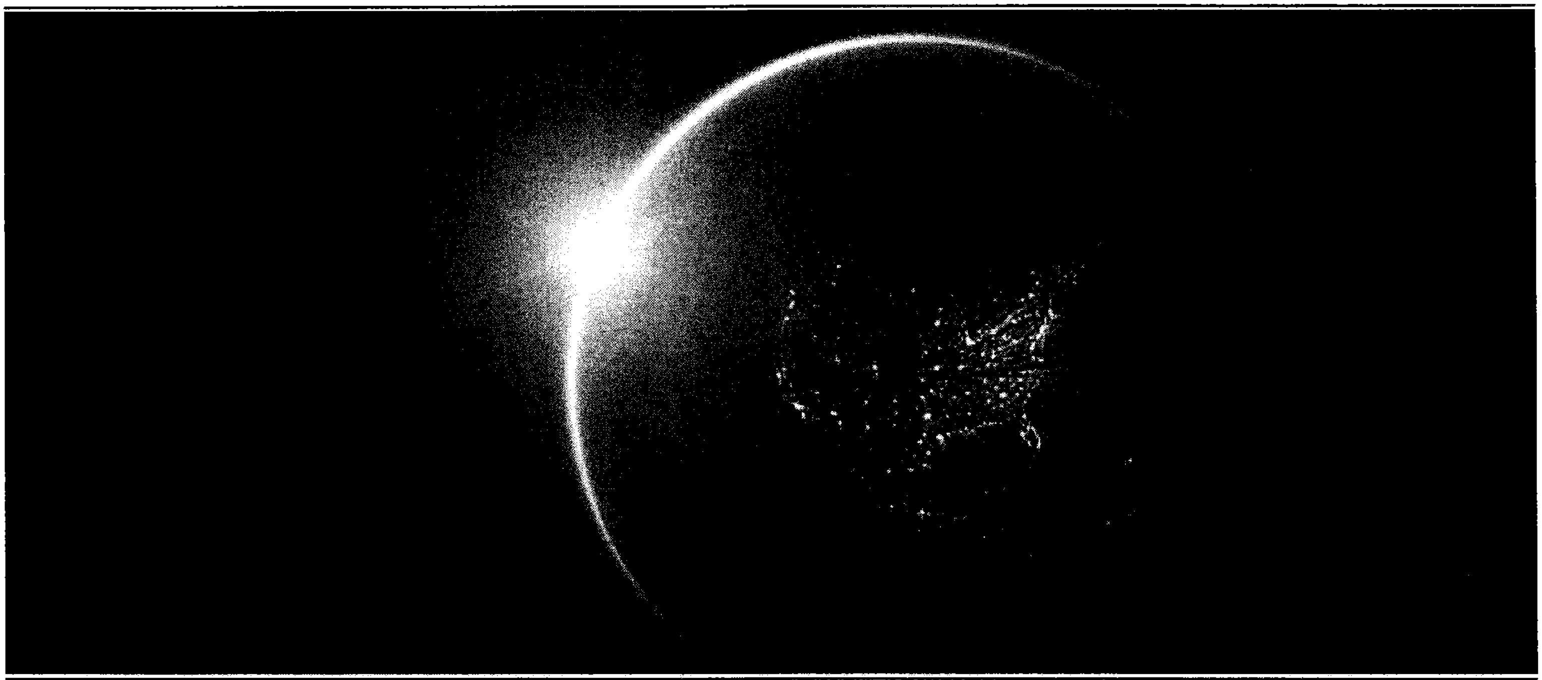
[24]Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1998,* DOE/EIA-0095(98) (Washington, DC, December 1998), pp. 9 and 13.

[25]Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System,* DOE/EIA-0618(98) (Washington, DC, May 1998), Table 14.

DOE/EIA-0383(2012) | June 2012

# Annual Energy Outlook 2012

## with Projections to 2035



Independent Statistics & Analysis
U.S. Energy Information Administration

# Executive summary

The projections in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2012 (AEO2012)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2012* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies. But *AEO2012* is not limited to the Reference case. It also includes 29 alternative cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy. Many of the implications of the alternative cases are discussed in the "Issues in focus" section of this report.

Key results highlighted in *AEO2012* include continued modest growth in demand for energy over the next 25 years and increased domestic crude oil and natural gas production, largely driven by rising production from tight oil and shale resources. As a result, U.S. reliance on imported oil is reduced; domestic production of natural gas exceeds consumption, allowing for net exports; a growing share of U.S. electric power generation is met with natural gas and renewables; and energy-related carbon dioxide emissions remain below their 2005 level from 2010 to 2035, even in the absence of new Federal policies designed to mitigate greenhouse gas (GHG) emissions.

### The rate of growth in energy use slows over the projection period, reflecting moderate population growth, an extended economic recovery, and increasing energy efficiency in end-use applications

Overall U.S. energy consumption grows at an average annual rate of 0.3 percent from 2010 through 2035 in the *AEO2012* Reference case. The U.S. does not return to the levels of energy demand growth experienced in the 20 years prior to the 2008-2009 recession, because of more moderate projected economic growth and population growth, coupled with increasing levels of energy efficiency. For some end uses, current Federal and State energy requirements and incentives play a continuing role in requiring more efficient technologies. Projected energy demand for transportation grows at an annual rate of 0.1 percent from 2010 through 2035 in the Reference case, and electricity demand grows by 0.7 percent per year, primarily as a result of rising energy consumption in the buildings sector. Energy consumption per capita declines by an average of 0.6 percent per year from 2010 to 2035 (Figure 1). The energy intensity of the U.S. economy, measured as primary energy use in British thermal units (Btu) per dollar of gross domestic product (GDP) in 2005 dollars, declines by an average of 2.1 percent per year from 2010 to 2035. New Federal and State policies could lead to further reductions in energy consumption. The potential impact of technology change and the proposed vehicle fuel efficiency standards on energy consumption are discussed in "Issues in focus."

### Domestic crude oil production increases

Domestic crude oil production has increased over the past few years, reversing a decline that began in 1986. U.S. crude oil production increased from 5.0 million barrels per day in 2008 to 5.5 million barrels per day in 2010. Over the next 10 years, continued development of tight oil, in combination with the ongoing development of offshore resources in the Gulf of Mexico, pushes domestic crude oil production higher. Because the technology advances that have provided for recent increases in supply are still in the early stages of development, future U.S. crude oil production could vary significantly, depending on the outcomes of key uncertainties related to well placement and recovery rates. Those uncertainties are highlighted in this *Annual Energy Outlook*'s "Issues in focus" section, which includes an article examining impacts of uncertainty about current estimates of the crude oil and natural gas resources. The *AEO2012* projections considering variations in these variables show total U.S. crude oil production in 2035 ranging from 5.5 million barrels per day to 7.8 million barrels per day, and projections for U.S. tight oil production from eight selected plays in 2035 ranging from 0.7 million barrels per day to 2.8 million barrels per day (Figure 2).

**Figure 1. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980=1)**

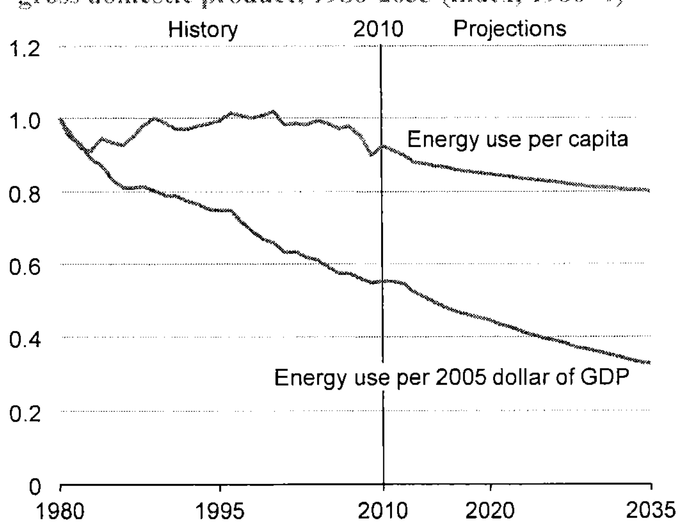
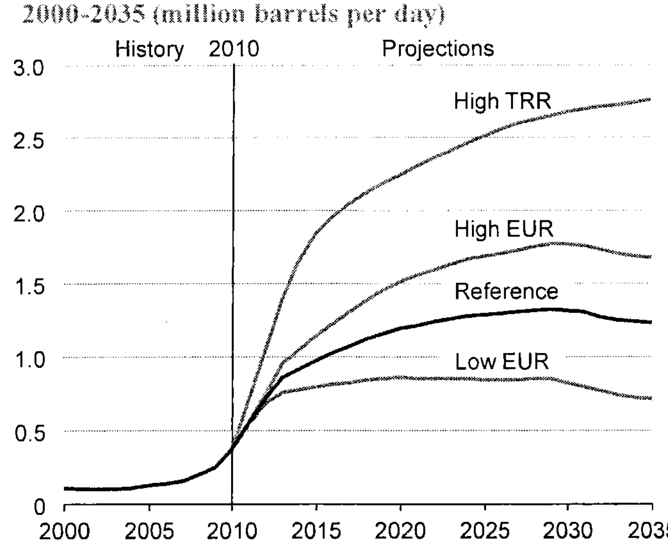



**Figure 2. U.S. production of tight oil in four cases, 2000-2035 (million barrels per day)**



### With modest economic growth, increased efficiency, growing domestic production, and continued adoption of nonpetroleum liquids, net imports of petroleum and other liquids make up a smaller share of total U.S. energy consumption

U.S. dependence on imported petroleum and other liquids declines in the *AEO2012* Reference case, primarily as a result of rising energy prices; growth in domestic crude oil production to more than 1 million barrels per day above 2010 levels in 2020; an increase of 1.2 million barrels per day crude oil equivalent from 2010 to 2035 in the use of biofuels, much of which is produced domestically; and slower growth of energy consumption in the transportation sector as a result of existing corporate average fuel economy standards. Proposed fuel economy standards covering vehicle model years (MY) 2017 through 2025 that are not included in the Reference case would further reduce projected need for liquid imports.

Although U.S. consumption of petroleum and other liquid fuels continues to grow through 2035 in the Reference case, the reliance on imports of petroleum and other liquids as a share of total consumption declines. Total U.S. consumption of petroleum and other liquids, including both fossil fuels and biofuels, rises from 19.2 million barrels per day in 2010 to 19.9 million barrels per day in 2035 in the Reference case. The net import share of domestic consumption, which reached 60 percent in 2005 and 2006 before falling to 49 percent in 2010, continues falling in the Reference case to 36 percent in 2035 (Figure 3). Proposed light-duty vehicles (LDV) fuel economy standards covering vehicle MY 2017 through 2025, which are not included in the Reference case, could further reduce demand for petroleum and other liquids and the need for imports, and increased supplies from U.S. tight oil deposits could also significantly decrease the need for imports, as discussed in more detail in "Issues in focus."

### Natural gas production increases throughout the projection period, allowing the United States to transition from a net importer to a net exporter of natural gas

Much of the growth in natural gas production in the *AEO2012* Reference case results from the application of recent technological advances and continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value than dry natural gas in energy equivalent terms. Shale gas production increases in the Reference case from 5.0 trillion cubic feet per year in 2010 (23 percent of total U.S. dry gas production) to 13.6 trillion cubic feet per year in 2035 (49 percent of total U.S. dry gas production). As with tight oil, when looking forward to 2035, there are unresolved uncertainties surrounding the technological advances that have made shale gas production a reality. The potential impact of those uncertainties results in a range of outcomes for U.S. shale gas production from 9.7 to 20.5 trillion cubic feet per year when looking forward to 2035.

As a result of the projected growth in production, U.S. natural gas production exceeds consumption early in the next decade in the Reference case (Figure 4). The outlook reflects increased use of liquefied natural gas in markets outside North America, strong growth in domestic natural gas production, reduced pipeline imports and increased pipeline exports, and relatively low natural gas prices in the United States.

### Power generation from renewables and natural gas continues to increase

In the Reference case, the natural gas share of electric power generation increases from 24 percent in 2010 to 28 percent in 2035, while the renewables share grows from 10 percent to 15 percent. In contrast, the share of generation from coal-fired power plants declines. The historical reliance on coal-fired power plants in the U.S. electric power sector has begun to wane in recent years.

**Figure 3. Total U.S. petroleum and other liquids production, consumption, and net imports, 1970-2035 (million barrels per day)**

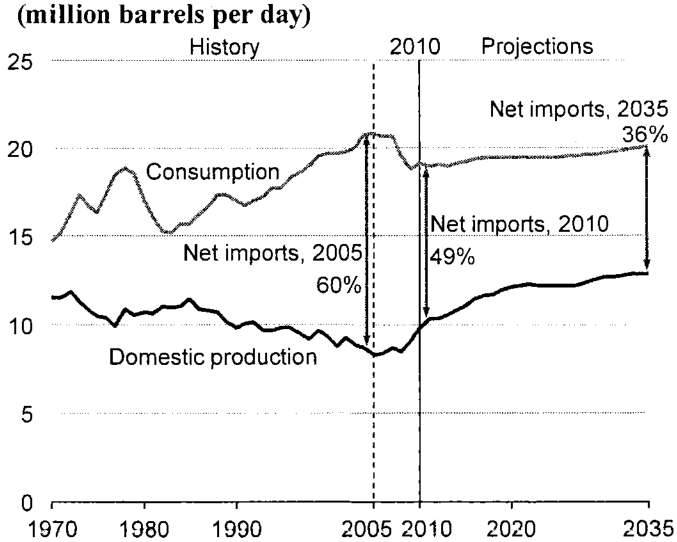
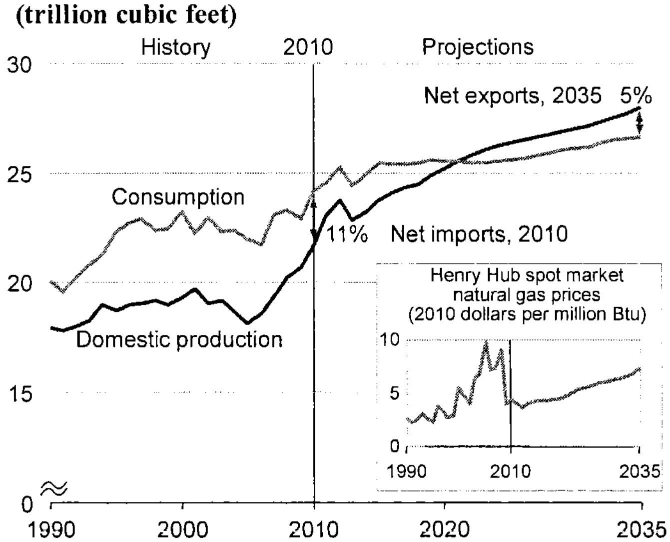



**Figure 4. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)**



Over the next 25 years, the share of electricity generation from coal falls to 38 percent, well below the 48-percent share seen as recently as 2008, due to slow growth in electricity demand, increased competition from natural gas and renewable generation, and the need to comply with new environmental regulations. Although the current trend toward increased use of natural gas and renewables appears fairly robust, there is uncertainty about the factors influencing the fuel mix for electricity generation. *AEO2012* includes several cases examining the impacts on coal-fired plant generation and retirements resulting from different paths for electricity demand growth, coal and natural gas prices, and compliance with upcoming environmental rules.

While the Reference case projects 49 gigawatts of coal-fired generation retirements over the 2011 to 2035 period, nearly all of which occurs over the next 10 years, the range for cumulative retirements of coal-fired power plants over the projection period varies considerably across the alternative cases (Figure 5), from a low of 34 gigawatts (11 percent of the coal-fired generator fleet) to a high of 70 gigawatts (22 percent of the fleet). The high end of the range is based on much lower natural gas prices than those assumed in the Reference case; the lower end of the range is based on stronger economic growth, leading to stronger growth in electricity demand and higher natural gas prices. Other alternative cases, with varying assumptions about coal prices and the length of the period over which environmental compliance costs will be recovered, but no assumption of new policies to limit GHG emissions from existing plants, also yield cumulative retirements within a range of 34 to 70 gigawatts. Retirements of coal-fired capacity exceed the high end of the range (70 gigawatts) when a significant GHG policy is assumed (for further description of the cases and results, see "Issues in focus").

## Total energy-related emissions of carbon dioxide in the United States remain below their 2005 level through 2035

Energy-related carbon dioxide ($CO_2$) emissions grow slowly in the *AEO2012* Reference case, due to a combination of modest economic growth, growing use of renewable technologies and fuels, efficiency improvements, slow growth in electricity demand, and increased use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, which assumes no explicit Federal regulations to limit GHG emissions beyond vehicle GHG standards (although State programs and renewable portfolio standards are included), energy-related $CO_2$ emissions grow by just over 2 percent from 2010 to 2035, to a total of 5,758 million metric tons in 2035 (Figure 6). $CO_2$ emissions in 2020 in the Reference case are more than 9 percent below the 2005 level of 5,996 million metric tons, and they still are below the 2005 level at the end of the projection period. Emissions per capita fall by an average of 1.0 percent per year from 2005 to 2035.

Projections for $CO_2$ emissions are sensitive to such economic and regulatory factors due to the pervasiveness of fossil fuel use in the economy. These linkages result in a range of potential GHG emissions scenarios. In the *AEO2012* Low and High Economic Growth cases, projections for total primary energy consumption in 2035 are, respectively, 100.0 quadrillion Btu (6.4 percent below the Reference case) and 114.4 quadrillion Btu (7.0 percent above the Reference case), and projections for energy-related $CO_2$ emissions in 2035 are 5,356 million metric tons (7.0 percent below the Reference case) and 6,117 million metric tons (6.2 percent above the Reference case).

**Figure 5. Cumulative retirements of coal-fired generating capacity, 2011-2035 (gigawatts)**

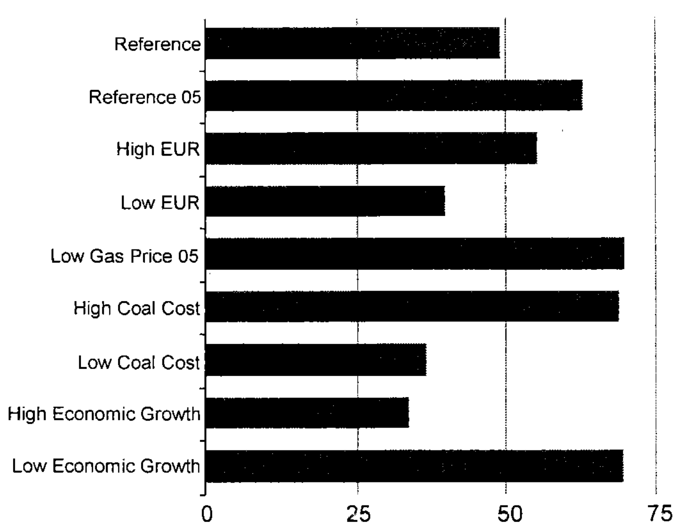
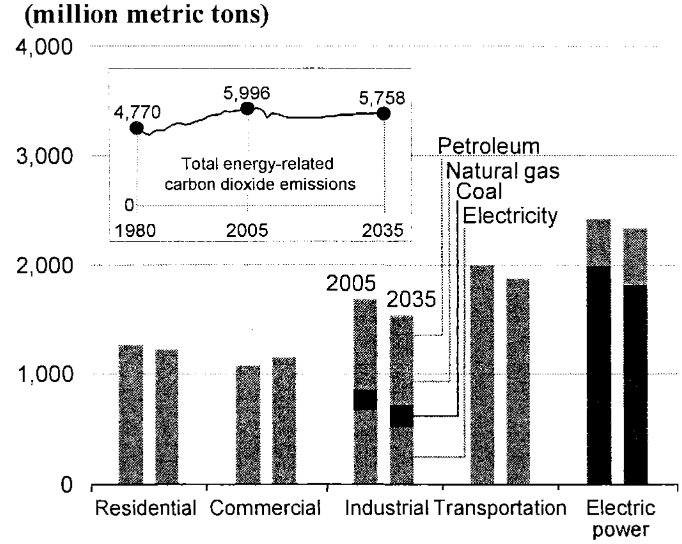


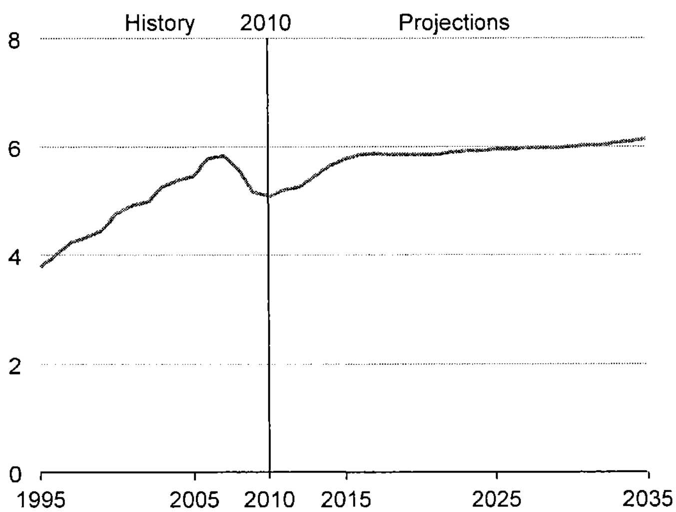

**Figure 6. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)**



# Electricity demand

## Heavy-duty vehicle energy demand continues to grow but slows from historical rates

Figure 92. Heavy-duty vehicle energy consumption, 1995-2035 (quadrillion Btu)



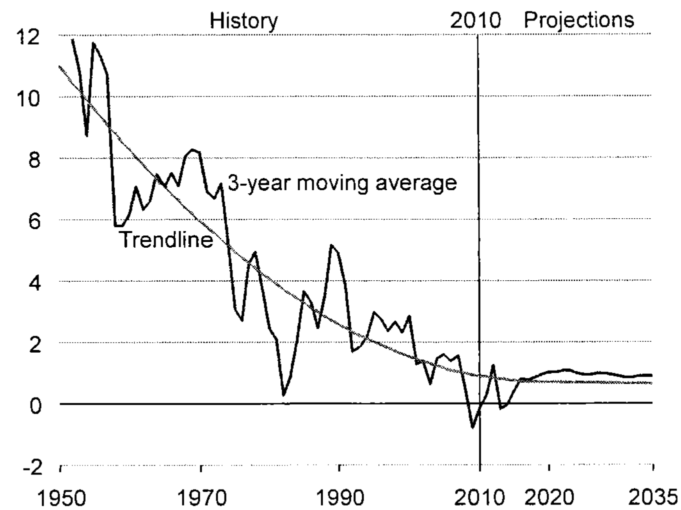

Energy demand for HDVs—including tractor trailers, vocational vehicles, heavy-duty pickups and vans, and buses—increases from 5.1 quadrillion Btu in 2010 to 6.2 quadrillion Btu in 2035, at an average annual growth rate of 0.8 percent, which is the highest among transportation modes. Still, the increase in energy demand for HDVs is lower than the 2-percent annual average from 1995 to 2010, as increases in VMT are offset by improvements in fuel economy following the recent introduction of new standards for HDV fuel efficiency and GHG emissions.

The total number of miles traveled annually by all HDVs grows by 48 percent from 2010 to 2035, from 234 billion miles to 345 billion miles, for an average annual increase of 1.6 percent. The rise in VMT is supported by rising economic output over the projection period and an increase in the number of trucks on the road, from 8.9 million in 2010 to 12.5 million in 2035.

Higher fuel economy for HDVs partially offsets the increase in their VMT, as average new vehicle fuel economy increases from 6.6 mpg in 2010 to 8.2 mpg in 2035. The gain in fuel economy is primarily a consequence of the new GHG emissions and fuel efficiency standards enacted by EPA and NHTSA that begin in MY 2014 and reach the most stringent levels in MY 2018 [*128*]. Fuel economy continues to improve moderately after 2018, as fuel-saving technologies continue to be adopted for economic reasons (Figure 92).

## Residential and commercial sectors dominate electricity demand growth

Figure 93. U.S. electricity demand growth, 1950-2035 (percent, 3-year moving average)



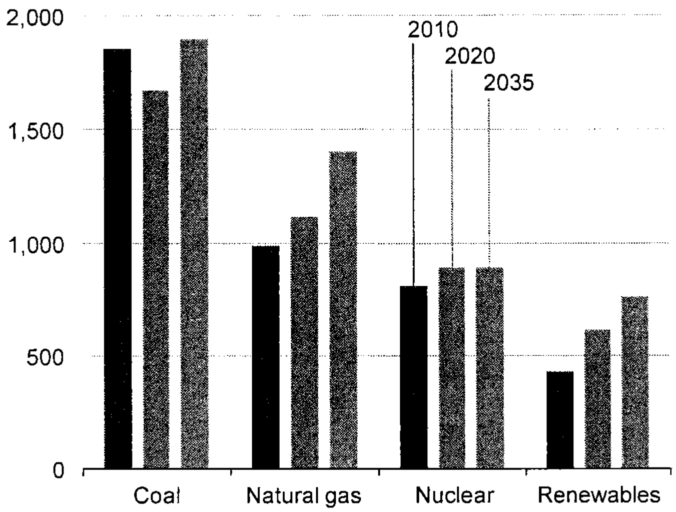

Electricity demand (including retail sales and direct use) growth has slowed in each decade since the 1950s, from a 9.8-percent annual rate of growth from 1949 to 1959 to only 0.7 percent per year in the first decade of the 21st century. In the *AEO2012* Reference case, electricity demand growth rebounds somewhat from those low levels but remains relatively slow, as growing demand for electricity services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure 93).

Electricity demand grows by 22 percent in the *AEO2012* Reference case, from 3,877 billion kilowatthours in 2010 to 4,716 billion kilowatthours in 2035. Residential demand grows by 18 percent over the same period, to 1,718 billion kilowatthours in 2035, spurred by population growth, rising disposable income, and continued population shifts to warmer regions with greater cooling requirements. Commercial sector electricity demand increases by 28 percent, to 1,699 billion kilowatthours in 2035, led by demand in the service industries. In the industrial sector, electricity demand has been generally declining since 2000, and it grows by only 2 percent from 2010 to 2035, slowed by increased competition from overseas manufacturers and a shift of U.S. manufacturing toward consumer goods that require less energy to produce. Electricity demand in the transportation sector is small, but it is expected to more than triple from 7 billion kilowatthours in 2010 to 22 billion kilowatthours in 2035 as sales of electric plug-in LDVs increase.

Average annual electricity prices (in 2010 dollars) increase by 3 percent from 2010 to 2035 in the Reference case, generally falling through 2020 in response to lower fuel prices used to generate electricity. After 2020, rising fuel costs more than offset lower costs for transmission and distribution.

## Coal-fired plants continue to be the largest source of U.S. electricity generation

**Figure 94. Electricity generation by fuel, 2010, 2020, and 2035 (billion kilowatthours)**




Coal remains the dominant fuel for electricity generation in the *AEO2012* Reference case (Figure 94), but its share declines significantly. In 2010, coal accounted for 45 percent of total U.S. generation; in 2020 and 2035 its projected share of total generation is 39 percent and 38 percent, respectively. Competition from natural gas and renewables is a key factor in the decline. Overall, coal-fired generation in 2035 is 2 percent higher than in 2010 but still 6 percent below the 2007 pre-recession level.

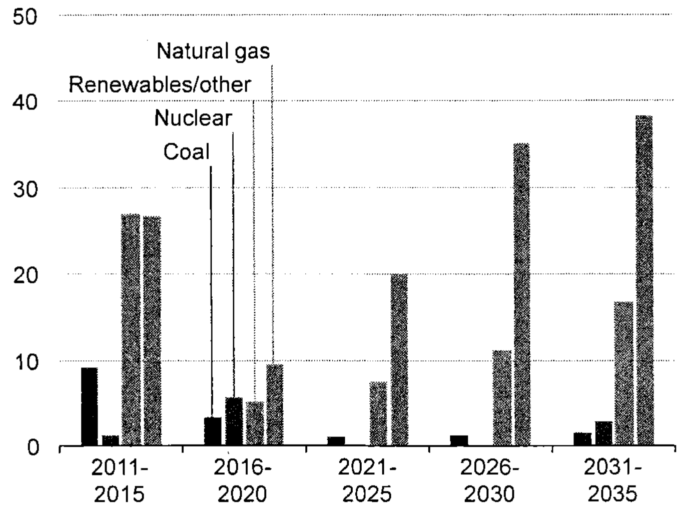
Generation from natural gas grows by 42 percent from 2010 to 2035, and its share of total generation increases from 24 percent in 2010 to 28 percent in 2035. The relatively low cost of natural gas makes the dispatching of existing natural gas plants more competitive with coal plants and, in combination with relatively low capital costs, makes natural gas the primary choice to fuel new generation capacity.

Generation from renewable sources grows by 77 percent in the Reference case, raising its share of total generation from 10 percent in 2010 to 15 percent in 2035. Most of the growth in renewable electricity generation comes from wind and biomass facilities, which benefit from State RPS requirements, Federal tax credits, and, in the case of biomass, the availability of low-cost feedstocks and the RFS.

Generation from U.S. nuclear power plants increases by 10 percent from 2010 to 2035, but the share of total generation declines from 20 percent in 2010 to 18 percent in 2035. Although new nuclear capacity is added by new reactors and uprates of older ones, total generation grows faster and the nuclear share falls. Nuclear capacity grows from 101 gigawatts in 2010 to 111 gigawatts in 2035, with 7.3 gigawatts of additional uprates and 8.5 gigawatts of new capacity between 2010 and 2035. Some older nuclear capacity is retired, which reduces overall nuclear generation.

## Most new capacity additions use natural gas and renewables

**Figure 95. Electricity generation capacity additions by fuel type, including combined heat and power, 2011-2035 (gigawatts)**




Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [*129*]. With growing electricity demand and the retirement of 88 gigawatts of existing capacity, 235 gigawatts of new generating capacity (including end-use combined heat and power) are projected to be added between 2011 and 2035 (Figure 95).

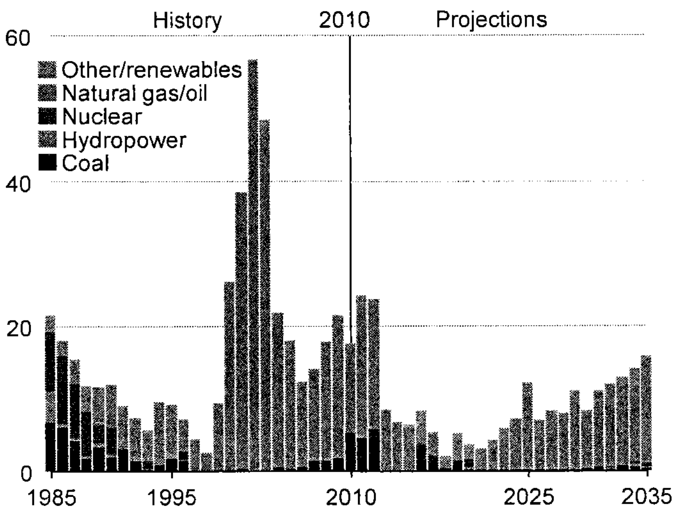
Natural-gas-fired plants account for 60 percent of capacity additions between 2011 and 2035 in the Reference case, compared with 29 percent for renewables, 7 percent for coal, and 4 percent for nuclear. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. Current Federal and State environmental regulations also affect fossil fuel use, particularly coal. Uncertainty about future limits on GHG emissions and other possible environmental programs also reduces the competitiveness of coal-fired plants (reflected in *AEO2012* by adding 3 percentage points to the cost of capital for new coal-fired capacity).

Uncertainty about demand growth and fuel prices also affects capacity planning. Total capacity additions from 2011 to 2035 range from 166 gigawatts in the Low Economic Growth case to 305 gigawatts in the High Economic Growth case. In the *AEO2012* Low Tight Oil and Shale Gas Resource case, natural gas prices are higher than in the Reference case and new natural gas fired capacity from 2011 to 2035 accounts for 102 gigawatts, which represents 47 percent of total additions. In the High Tight Oil and Shale Gas Resource case, delivered natural gas prices are lower than in the Reference case and natural gas-fired capacity additions by 2035 are 155 gigawatts, or 66 percent of total new capacity.

# Electricity sales

## Additions to power plant capacity slow after 2012 but accelerate beyond 2020

**Figure 96. Additions to electricity generating capacity,** 1985-2035 (gigawatts)



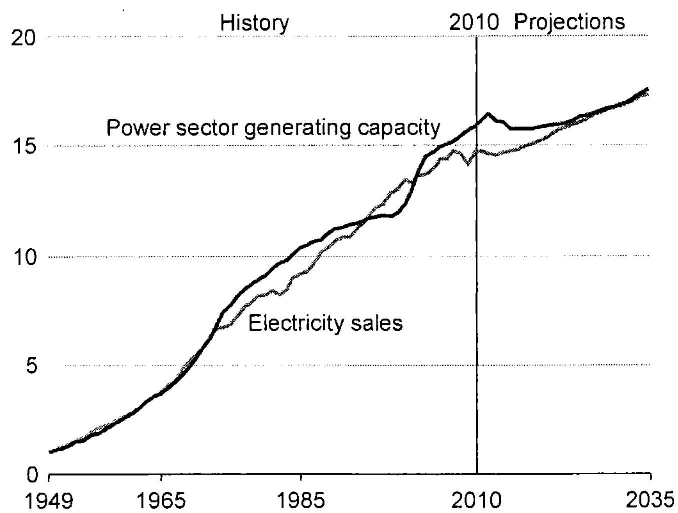

Typically, investments in electricity generation capacity have gone through "boom and bust" cycles. Periods of slower growth have been followed by strong growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring (Figure 96). A construction boom in the early 2000s saw capacity additions averaging 35 gigawatts a year from 2000 to 2005, much higher than had been seen before. Since then, average annual builds have dropped to 17 gigawatts per year from 2006 to 2010.

In the *AEO2012* Reference case, capacity additions between 2011 and 2035 total 235 gigawatts, including new plants built not only in the power sector but also by end-use generators. Annual additions in 2011 and 2012 remain relatively high, averaging 24 gigawatts per year [*130*]. Of those early builds, about 40 percent are renewable plants built to take advantage of Federal tax incentives and to meet State renewable standards.

Annual builds drop significantly after 2012 and remain below 9 gigawatts per year until 2025. During that period, existing capacity is adequate to meet growth in demand in most regions, given the earlier construction boom and relatively slow growth in electricity demand after the economic recession. Between 2025 and 2035, average annual builds increase to 11 gigawatts per year, as excess capacity is depleted and the rate of total capacity growth is more consistent with electricity demand growth. More than 70 percent of the capacity additions from 2025 to 2035 are natural gas fired, given the higher construction costs for other capacity types and uncertainty about the prospects for future limits on GHG emissions.

## Growth in generating capacity parallels rising demand for electricity

**Figure 97. Electricity sales and power sector generating** capacity, 1949-2035 (index, 1949 = 1.0)




Over the long term, growth in electricity generating capacity parallels the growth in end-use demand for electricity. However, unexpected shifts in demand or dramatic changes affecting capacity investment decisions can cause imbalances that can take years to work out.

Figure 97 shows indexes summarizing relative changes in total generating capacity and electricity demand. During the 1950s and 1960s, the capacity and demand indexes tracked closely. The energy crises of the 1970s and 1980s, together with other factors, slowed electricity demand growth, and capacity growth outpaced demand for more than 10 years thereafter, as planned units continued to come on line. Demand and capacity did not align again until the mid-1990s. Then, in the late 1990s, uncertainty about deregulation of the electricity industry caused a downturn in capacity expansion, and another period of imbalance followed, with growth in electricity demand exceeding capacity growth.

In 2000, a boom in construction of new natural gas fired plants began, quickly bringing capacity back into balance with demand and, in fact, creating excess capacity. Construction of new intermittent wind capacity that sometimes needs backup capacity also began to grow after 2000. More recently, the 2008-2009 economic recession caused a significant drop in electricity demand, which has recovered only partially in the post-recession period. In combination with slow near-term growth in electricity demand, the slow economic recovery creates excess generating capacity in the *AEO2012* Reference case. Capacity currently under construction is completed in the Reference case, but only a limited amount of additional capacity is built before 2025, while older capacity is retired. In 2025, capacity growth and demand growth are in balance again, and they grow at similar rates through 2035.

San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

**PERMIT NO:** S-3523-1-2 **ISSUANCE DATE:** 03/30/2000

**LEGAL OWNER OR OPERATOR:** ELK HILLS POWER LLC
**MAILING ADDRESS:** P O BOX 460
4026 SKYLINE ROAD
TUPMAN, CA 93276

**LOCATION:** NW CORNER OF ELK HILLS RD & SKYLINE RD
CA

**SECTION:** NE35 **TOWNSHIP:** 30S **RANGE:** 23E

**EQUIPMENT DESCRIPTION:**
MODIFICATION OF PREVIOUSLY AUTHORIZED GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALYST, AND STEAM TURBINE SHARED WITH S-3532-2 (503 MW TOTAL PLANT NOMINAL RATING): ALLOW REDUCTION OF PM10 EMISSION LIMITS AND PM10 OFFSET REQUIREMENTS BASED ON INITIAL SOURCE TEST RESULTS

## CONDITIONS

1. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. Permittee shall submit selective catalytic reduction, oxidation catalyst, and continuous emission monitor design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]
3. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201]
4. CTG shall be equipped with continuously recording fuel gas flowmeter. [District Rule 2201]
5. CTG exhaust shall be equipped with continuously recording emissions monitor (CEM) for NOx (before and after the SCR unit), CO, and O2 dedicated to this unit. Continuous emission monitors shall meet the requirements of 40 CFR Part 60 Appendices B & F, and 40 CFR Part 75, and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. If relative accuracy of CEM(s) cannot be certified during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained during source testing to determine compliance with emission limits in conditions 15, 18, 19, & 20. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 326-6900 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

DAVID L. CROW, Executive Director / APCO

SEYED SADREDIN, Director of Permit Services
S-3523-1-2 Dec 18 2002 4 24PM – TOMLINS : Joint Inspection Required with TOMLINS

6. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]
7. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]
8. Ammonia injection grid shall be equipped with operational ammonia flowmeter and injection pressure indicator. [District Rule 2201]
9. Exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods. [District Rule 1081]
10. Heat recovery steam generator design shall provide space for additional selective catalytic reduction catalyst and oxidation catalyst if required to meet NOx and CO emission limits. [District Rule 2201]
11. Permittee shall monitor and record exhaust gas temperature at selective catalytic reduction and oxidation catalyst inlets. [District Rule 2201]
12. CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]
13. Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmv emission limits in condition 15. Shutdown is defined the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed two hours for a regular startup, four hours for an extended startup, and one hour for a shutdown, per occurrence. [District Rule 2201 and 4001]
14. Ammonia shall be injected when the selective catalytic reduction system catalyst temperature exceeds 500 degrees F. Permittee shall monitor and record catalyst temperature during periods of startup. [District Rule 2201]
15. During startup or shutdown of any gas turbine engine(s), combined emissions from both gas turbine engines (S-3523-1 and -2) heat recovery steam generator exhausts shall not exceed any of the following: NOx (as NO2) - 76 lb and CO - 38 lb in any one hour. [CEQA]
16. By two hours after turbine initial firing, CTG exhaust emissions shall not exceed any of the following: NOx (as NO2) - 12.2 ppmv @ 15% O2 and CO - 25 ppmv @ 15% O2. [District Rule 4703]
17. Emission rates from each CTG, except during startup and/or shutdown, shall not exceed any of the following: PM10 - 18.0 lb/hr, SOx (as SO2) - 3.6 lb/hr, NOx (as NO2) - 15.8 lb/hr and 2.5 ppmvd @ 15% O2, VOC - 4.0 lb/hr and 2.0 ppmvd @ 15% O2, CO - 12.5 lb/hr and 4 ppmvd @ 15% O2, ammonia - 10 ppmvd @15% O2. NOx (as NO2) emission limit is a one-hour rolling average. Ammonia emission limit is a twenty-four hour rolling average. All other emission limits are three-hour rolling averages. [District Rules 2201, 4001, and 4703]
18. Emission rates from each CTG, on days when a startup or shutdown occurs, shall not exceed any of the following: PM10 - 432.0 lb/day, SOx (as SO2) - 86.4 lb/day, NOx (as NO2) - 418.5 lb/day, VOC - 96.0 lb/day, and CO - 326.7 lb/day. [District Rule 2201]
19. Emission rates from both CTGs (S-3523-1 and -2), on days when a startup or shutdown occurs for either or both turbines, shall not exceed any of the following: PM10 - 864.0 lb/day, SOx (as SO2) - 172.8 lb/day, NOx (as NO2) - 817.8 lb/day, VOC - 192.0 lb/day, and CO - 640.4 lb/day. [District Rule 2201]
20. Annual emissions from both CTGs calculated on a twelve consecutive month rolling basis shall not exceed any of the following: PM10 - 315,360 lb/year , SOx (as SO2) - 57,468 lb/year, NOx (as NO2) - 285,042 lb/year, VOC - 64,478 lb/year, and CO - 223,040 lb/year. [District Rule 2201]
21. Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a three-hour rolling average will commence on the hour. The three-hour average will be compiled from the three most recent one-hour periods. Each one-hour period in a twenty-four-hour average for ammonia slip will commence on the hour. The twenty-four-hour average will be calculated starting and ending at twelve-midnight. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

22. Daily emissions will be compiled for a twenty-four period starting and ending at twelve-midnight. Each calendar month in a twelve-consecutive-month rolling emissions will commence at the beginning of the first day of the month. The twelve-consecutive-month rolling emissions total to determine compliance with annual emissions will be compiled from the twelve most recent calendar months. [District Rule 2201]

23. Prior to commencement of operation of the equipment covered by permit numbers S-3523-1, -2, & 3, emission offsets shall be tendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1, PM10 - Q1: 78,596 lb, Q2: 79,470 lb, Q3: 80,343 lb; and Q4: 80,343 lb; SOx (as SO2) - Q1: 14,170 lb, Q2: 14,328 lb , Q3: 14,485 lb, and Q4: 14,485 lb; NOx (as NO2) - Q1: 65,353 lb, Q2: 66,079 lb, Q3: 66,805 lb, and Q4: 66,805 lb; and VOC - Q1: 10,967 lb, Q2: 11,089 lb, Q3: 11,211 lb, and Q4: 11,211 lb. [District Rule 2201]

24. NOx and VOC emission reductions that occurred from April through November may be used to offset increases in NOx and VOC respectively during any period of the year. [District Rule 2201]

25. NOx ERCs may be used to offset PM10 emission increases at a ratio of 2.42 lb NOx : 1 lb PM10 for reductions occurring within 15 miles of this facility, and at 2.72 lb NOx : 1 lb PM10 for reductions occurring greater than 15 miles from this facility [District Rule 2201]

26. At least 30 days prior to commencement of construction, the permittee shall provide the District with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into. [District Rule 2201]

27. Compliance with ammonia slip limit shall be demonstrated by using the following calculation procedure: ammonia slip ppmv @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000 / b) x d, where a = ammonia injection rate(lb/hr)/17(lb/lb. mol), b = dry exhaust gas flow rate (lb/hr)/(29(lb/lb. mol), c = change in measured NOx concentration ppmv at 15% O2 across catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District, to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee must submit a monitoring plan for District review and approval [District Rule 4102]

28. Compliance with the short term emission limits (lb/hr and ppmv @ 15% O2) shall be demonstrated within 60 days of initial operation of each gas turbine engine and annually thereafter by District witnessed in situ sampling of exhaust gasses by a qualified independent source test firm at full load conditions as follows - NOx: ppmvd @ 15% O2 and lb/hr, CO: ppmvd @ 15% O2 and lb/hr, VOC: ppmvd @ 15% O2 and lb/hr, PM10: lb/hr, and ammonia: ppmvd @ 15% O2. Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rule 1081]

29. Compliance with the startup NOx, CO, and VOC mass emission limits shall be demonstrated for one of the CTGs (S-3523-1, or -2) upon initial operation and at least every seven years thereafter by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081]

30. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days of operation of each gas turbine engine and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]

31. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source tests required by conditions on this permit shall be submitted to the District within 60 days of testing. [District Rule 1081]

32. Source test plans for initial and seven-year source tests shall include a method for measuring the VOC/CO surrogate relationship that will be used to demonstrate compliance with VOC lb/hr, lb/day, and lb/twelve month rolling emission limits. [District Rule 2201]

33. The following test methods shall be used PM10: EPA method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

34. The permittee shall notify District of date of initiation of construction no later than 30 days after such date, date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and date of actual startup within 15 days after such date. [District Rule 4001]

CONDITIONS CONTINUE ON NEXT PAGE

35. The permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmv @ 15% O2), and hourly, daily, and twelve month rolling average records of NOx and CO emissions. Compliance with the hourly, daily, and twelve month rolling average VOC emission limits shall be demonstrated by the CO CEM data and the VOC/CO relationship determined by annual CO and VOC source tests. [District Rule 2201]

36. The permittee shall maintain records of SOx lb/hr, lb/day, and lb/twelve month rolling average emission. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201]

37. Permittee shall maintain the following records for the CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 & 4703]

38. Permittee shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 & 4703]

39. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rule 2201]

40. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3. 3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

41. The permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the Districts satisfaction that the longer reporting period was necessary. [District Rule 1100]

42. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

43. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

44. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F . [District Rule 1080]

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

46. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program 24 months before the unit commences operation. [District Rule 2540]

47. Permittee may lower hourly, daily, and rolling twelve-month PM10 emission limits in Conditions 17, 18, 19, and 20, and thereby reduce PM10 offset requirements set forth in condition 23, based on actual PM10 emissions demonstrated during initial source tests. Revised emission limits shall be submitted to the District within 60 days after the last unit is initially source tested. The District will reflect revised limits in the Permit to Operate for the subject equipment. Any emission reduction credit (ERC) certificates, or portions thereof, that were tendered to the District but are not needed to meet reduced PM10 offset requirements will be returned to the permittee at full value. The permittee shall indicate which ERC certificates are to be retired. [District Rule 2201]

San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

**PERMIT NO:** S-3523-2-2

**ISSUANCE DATE:** 03/30/2000

**LEGAL OWNER OR OPERATOR:** ELK HILLS POWER LLC
**MAILING ADDRESS:** P O BOX 460
4026 SKYLINE ROAD
TUPMAN, CA 93276

**LOCATION:** NW CORNER OF ELK HILLS RD & SKYLINE RD
CA

**SECTION:** NE35 **TOWNSHIP:** 30S **RANGE:** 23E

**EQUIPMENT DESCRIPTION:**
MODIFICATION OF PREVIOUSLY AUTHORIZED GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #2 WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALYST, AND STEAM TURBINE SHARED WITH S-3532-1 (503 MW TOTAL PLANT NOMINAL RATING): ALLOW REDUCTION OF PM10 EMISSION LIMITS AND PM10 OFFSET REQUIREMENTS BASED ON INITIAL SOURCE TEST RESULTS

## CONDITIONS

1. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. Permittee shall submit selective catalytic reduction, oxidation catalyst, and continuous emission monitor design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]
3. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201]
4. CTG shall be equipped with continuously recording fuel gas flowmeter. [District Rule 2201]
5. CTG exhaust shall be equipped with continuously recording emissions monitor (CEM) for NOx (before and after the SCR unit), CO, and O2 dedicated to this unit. Continuous emission monitors shall meet the requirements of 40 CFR Part 60 Appendices B & F, and 40 CFR Part 75, and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. If relative accuracy of CEM(s) cannot be certified during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained during source testing to determine compliance with emission limits in conditions 15, 18 19, & 20. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 326-6900 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

DAVID L. CROW, Executive Director / APCO

SEYED SADREDIN, Director of Permit Services

S-3523-2-2 . Dec 18 2002 4 24PM – TOMLINS : Joint Inspection Required with TOMLINS

22. Daily emissions will be compiled for a twenty-four period starting and ending at twelve-midnight. Each calendar month in a twelve-consecutive-month rolling emissions will commence at the beginning of the first day of the month. The twelve-consecutive-month rolling emissions total to determine compliance with annual emissions will be compiled from the twelve most recent calendar months. [District Rule 2201]

23. Prior to commencement of operation of the equipment covered by permit numbers S-3523-1, -2, & 3, emission offsets shall be tendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1, PM10 - Q1: 78,596 lb, Q2: 79,470 lb, Q3: 80,343 lb, and Q4: 80,343 lb; SOx (as SO2) - Q1: 14,170 lb, Q2: 14,328 lb , Q3: 14,485 lb, and Q4: 14,485 lb; NOx (as NO2) - Q1: 65,353 lb, Q2: 66,079 lb, Q3: 66,805 lb, and Q4: 66,805 lb; and VOC - Q1: 10,967 lb, Q2: 11,089 lb, Q3: 11,211 lb, and Q4: 11,211 lb. [District Rule 2201]

24. NOx and VOC emission reductions that occurred from April through November may be used to offset increases in NOx and VOC respectively during any period of the year. [District Rule 2201]

25. NOx ERCs may be used to offset PM10 emission increases at a ratio of 2.42 lb NOx : 1 lb PM10 for reductions occurring within 15 miles of this facility, and at 2.72 lb NOx : 1 lb PM10 for reductions occurring greater than 15 miles from this facility [District Rule 2201]

26. At least 30 days prior to commencement of construction, the permittee shall provide the District with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into. [District Rule 2201]

27. Compliance with ammonia slip limit shall be demonstrated by using the following calculation procedure: ammonia slip ppmv @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000 / b) x d, where a = ammonia injection rate(lb/hr)/17(lb/lb. mol), b = dry exhaust gas flow rate (lb/hr)/(29(lb/lb. mol), c = change in measured NOx concentration ppmv at 15% O2 across catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District, to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee must submit a monitoring plan for District review and approval [District Rule 4102]

28. Compliance with the short term emission limits (lb/hr and ppmv @ 15% O2) shall be demonstrated within 60 days of initial operation of each gas turbine engine and annually thereafter by District witnessed in situ sampling of exhaust gasses by a qualified independent source test firm at full load conditions as follows - NOx: ppmvd @ 15% O2 and lb/hr, CO: ppmvd @ 15% O2 and lb/hr, VOC: ppmvd @ 15% O2 and lb/hr, PM10: lb/hr, and ammonia: ppmvd @ 15% O2. Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rule 1081]

29. Compliance with the startup NOx, CO, and VOC mass emission limits shall be demonstrated for one of the CTGs (S-3523-1, or -2) upon initial operation and at least every seven years thereafter by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081]

30. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days of operation of each gas turbine engine and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]

31. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source tests required by conditions on this permit shall be submitted to the District within 60 days of testing. [District Rule 1081]

32. Source test plans for initial and seven-year source tests shall include a method for measuring the VOC/CO surrogate relationship that will be used to demonstrate compliance with VOC lb/hr, lb/day, and lb/twelve month rolling emission limits. [District Rule 2201]

33. The following test methods shall be used PM10: EPA method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

34. The permittee shall notify District of date of initiation of construction no later than 30 days after such date, date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and date of actual startup within 15 days after such date. [District Rule 4001]

CONDITIONS CONTINUE ON NEXT PAGE

35. The permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmv @ 15% O2), and hourly, daily, and twelve month rolling average records of NOx and CO emissions. Compliance with the hourly, daily, and twelve month rolling average VOC emission limits shall be demonstrated by the CO CEM data and the VOC/CO relationship determined by annual CO and VOC source tests. [District Rule 2201]

36. The permittee shall maintain records of SOx lb/hr, lb/day, and lb/twelve month rolling average emission. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201]

37. Permittee shall maintain the following records for the CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 & 4703]

38. Permittee shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 & 4703]

39. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rule 2201]

40. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3. 3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

41. The permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the Districts satisfaction that the longer reporting period was necessary. [District Rule 1100]

42. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

43. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

44. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F . [District Rule 1080]

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

46. Permittee shall submit an application to comply with Rule 2540 - Acid Rain Program 24 months before the unit commences operation. [District Rule 2540]

47. Permittee may lower hourly, daily, and rolling twelve-month PM10 emission limits in Conditions 17, 18, 19, and 20, and thereby reduce PM10 offset requirements set forth in condition 23, based on actual PM10 emissions demonstrated during initial source tests. Revised emission limits shall be submitted to the District within 60 days after the last unit is initially source tested. The District will reflect revised limits in the Permit to Operate for the subject equipment. Any emission reduction credit (ERC) certificates, or portions thereof, that were tendered to the District but are not needed to meet reduced PM10 offset requirements will be returned to the permittee at full value. The permittee shall indicate which ERC certificates are to be retired. [District Rule 2201]

:ALIFORNIA ENERGY COMMISSION
16 NINTH STREET
\CRAMENTO, CA 95814-5512

STATE OF CALIFORNIA
State Energy Resources
Conservation and Development Commission

| | | |
|---|---|---|
| In the Matter of: | ) | Docket No. 99-AFC-1C |
| | ) | Order No. 03-0319-1(a) |
| Elk Hills Power Project | ) | |
| Petition to Allow for Tendering of $PM_{10}$ | ) | **COMMISSION ORDER APPROVING** |
| ERCs and for a Temporary Increase in | ) | **PROJECT MODIFICATION** |
| Commissioning Emissions | | |

On December 11, 2002, the California Energy Commission (Energy Commission) received a petition from Elk Hills Power, LLC to modify air quality Conditions of Certification to allow for tendering of $PM_{10}$ emission reduction credits based on the outcome of initial source tests, and to allow for a temporary increase in commissioning emissions. At a regularly scheduled Business Meeting on March 19, 2003, the Energy Commission considered staff's analysis and approved revised and new air quality Conditions of Certification in accordance with Title 20, section 1769(a)(3) of the California Code of Regulations, allowing for the tendering of emission reduction credits and for a temporary increase in emissions during commissioning.

COMMISSION FINDINGS

Based on staff's analysis, the Energy Commission finds that:

A. There will be no new or additional unmitigated significant environmental impacts associated with the proposed change.

B. The facility will remain in compliance with all applicable laws, ordinances, regulations, and standards, subject to the provisions of Public Resources code section 25525.

C. The change will be beneficial to the project owner by allowing for flexibility to reduce the amount of emission reductions credits surrendered to the San JoaquinValley Air Pollution Control District, and by allowing for operational efficiency during the commissioning phase.

D. There has been a substantial change since the Energy Commission certification based on the project owner's re-evaluation of operational issues that were not available during the siting process.

ORDER

The California Energy Commission hereby approves the tendering of $PM_{10}$ emission reduction credits based on the outcome of initial source tests, and approves a temporary increase in commissioning emissions.

NEW AND REVISIONS TO EXISTING CONDITIONS OF CERTIFICATION

(Deleted text is shown in ~~strikethrough~~, and new text is underlined).

**AQ-21** Prior to commencement of operation ~~or upon startup~~ of S-3523-1-0, -2-0, & 3-0, emission offsets shall be tendered ~~surrendered~~ for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1, PM10 - Q1: 78,596 lb, Q2: 79,470 lb, Q3: 80,343 lb, and Q4: 80,343 lb; and surrendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1, SOx (as SO2) - Q1: 14,170 lb, Q2: 14,328 lb , Q3: 14,485 lb, and Q4: 14,485 lb; NOx (as NO2) - Q1: 65,353 lb, Q2: 66,079 lb, Q3: 66,805 lb, and Q4: 66,805 lb; and VOC - Q1: 10,967 lb, Q2: 11,089 lb, Q3: 11,211 lb, and Q4: 11,211 lb. [District Rule 2201]

**Verification**: The owner/operator shall submit copies of ERCs tendered or surrendered to the SJVUAPCD in the totals shown to the CPM prior to commencement of operation ~~or upon startup~~ of the CTGs or cooling tower.

**AQ-63** The project owner may lower hourly, daily, and rolling average twelve-month PM10 emission limits in Conditions AQ-15, AQ-16, AQ-17, and AQ-18, and thereby reduce PM10 offset requirements set forth in AQ-21, based on actual PM10 emissions demonstrated during initial source tests. Revised emission limits shall be submitted to the District within 60 days after the last unit is initially source tested. The District will reflect revised limits in the permit to operate for the subject equipment. Any emission reduction credit certificates, or portions thereof, that were tendered to the District but are not needed to meet reduced PM10 offset requirements will be returned to the project owner at full value. The project owner shall indicate which emission reduction credit certificates are to be retired.

**Verification**: The project owner shall notify the CPM and District of any proposed changes in PM10 emission limits and indicate which ERC certificates are to be retired within 60 days after the last unit is initially source tested.

**AQ-64** Relief granted by the San Joaquin Valley Air Pollution Control District Hearing Board on November 13, 2002 in Regular Variance Docket No. S-02-38R shall apply to Conditions of Certification AQ-5, AQ-13 through AQ-17, AQ-26, and AQ-27. The Project Owner shall comply with all requirements incorporated into the 19 conditions of this regular variance.

**Verification**: The project owner shall submit copies of all notifications and reports required under this regular variance to the CPM. The project owner shall notify the CPM within 5 days of any requested changes to this variance.

**AQ-65** During commissioning, emissions shall be limited to 400 lbs/hour of $NO_x$ and 4,000 lbs/hour of CO.

**Verification**: The project owner shall provide, within 24 hours of occurrence, notification to the CPM of any noncompliance with the commissioning startup/shutdown emission limits.

IT IS SO ORDERED.

STATE OF CALIFORNIA
ENERGY RESOURCES
CONSERVATION AND
DEVELOPMENT COMMISSION

DATE March 19, 2003

WILLIAM J. KEESE, Chairman

**Request to Amend the Elk Hills Power Project (99-AFC-1C) to Allow $PM_{10}$ ERC Tendering and Commissioning Emissions Increase Staff Analysis February 28, 2003**

## Amendment Request

On December 10, 2002, Elk Hills Power, LLC (EHP or project owner) submitted to the Energy Commission a proposed amendment to the Elk Hills Power Project (EHPP) (EHP 2002). The amendment proposes to allow EHP to "tender" rather than "surrender" PM10 (particulate matter less than 10 microns in mean aerodynamic diameter) emission reduction credits (ERCs) to the San Joaquin Valley Air Pollution Control District (SJVAPCD or the District). Excess ERCs would be returned to EHP if EHP is able to justify a lower permitted PM10 emission rate from the combustion turbine and heat recovery steam generator stack based on the initial performance tests. On December 17, 2002, the SJVAPCD issued a revised approval to EHP's Authority to Construct (ATC) reflecting the possible revision of PM10 emission rates and offset requirements. The amendment request also includes a commissioning emissions variance, which was granted by the District on November 13, 2002 (District 2002).

## Background

In February 1999, the project owner proposed to construct and operate a 500 megawatt (MW) combined cycle project in western Kern County, approximately 25 miles west of Bakersfield, California. The EHPP was certified in December 2000 (CEC 2000a). The original project design included two natural gas fired 7F type combustion turbine generators (CTG), two heat recovery steam generators with duct firing, a steam turbine generator, a six-cell cooling tower, and a diesel fired emergency engine. There have been no previous project amendments that have requested the modification of operational air quality requirements. The EHPP is expected to be online in June 2003.

ERC Tendering

PM10 ERCs have become scarce in the SJVAPCD and as a result, have also escalated in price. Recent operating data from turbines similar to those being installed at EHPP have shown that PM10 emission rates may be lower then originally assumed during the licensing process. Thus, the amount of ERCs actually necessary to mitigate project air emission impacts may be less than the amounts that were originally required, which were based on equipment vendor guarantees. The project owner would like to have the flexibility to lower their permitted PM10 emissions limits based on the results of initial source testing to determine actual facility PM10 emissions. This, in turn, would reduce the quantity of ERCs that would need to be surrendered to mitigate project air impacts. Excess ERCs would be returned to EHP.

Prior to changing any permit levels or associated ERC requirements, EHP would be required to submit a separate amendment request to the Energy Commission and the District with the results of initial source testing and associated data regarding actual PM10 emission rates.

Commissioning Variance

Neither the original District Determination of Compliance, nor the original Staff Assessment (CEC 2000b) evaluated commissioning emissions or provided Conditions of Certification to address emission requirements during commissioning. Emissions of nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOC) are known to be elevated during commissioning, particularly in the early phases of commissioning prior to the installation and operation of the pollution control equipment. The project owner obtained a variance from the District and is requesting a similar amendment of the Energy Commission decision in order to maintain project compliance with emission requirements during the commissioning period.

**Laws, Ordinances, Regulations and Standards (LORS)**

The California State Health and Safety Code, section 41700, requires that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerate number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property."

The project would continue to remain in compliance with all applicable LORS with the requested changes.

**Analysis**

ERC Tendering

The concept of tendering would allow EHP to turn over PM10 ERCs to the District prior to the commencement of facility operation, just as if the ERCs were to be surrendered. However, the District will not withdraw the ERCs from use until EHPP completes their initial source testing and determines if they can operate EHPP at a lower PM10 limit.

EHP has acquired sufficient ERCs to offset maximum permitted plant emissions for VOC, SOx, NOx, and PM10 on a quarterly basis. The District has required EHP to surrender ERC certificates for all calendar quarters at appropriate offset ratios prior to commencement of operation of the equipment covered by the District ATC. Once surrendered, these ERCs would be under the control of the District.

EHP's ATC permit contains hourly, daily, and rolling twelve-month emission limits for PM10. There was very little operating experience with the GE7FA gas turbines in 1999 when emission estimates and guarantees were used as the basis for the project's permits. However, recent experience at other facilities has shown that measured PM10 rates may be substantially lower. The difference between any new PM10 limits that may be requested and changes to current permit limits would be based solely on actual measurements at EHPP during initial source testing. There would be no physical modifications to the facility to achieve lower limits, nor any changes in operating conditions or assumptions. The request would be limited to PM10 emissions.

If the initial source tests indicate that EHPP can operate at lower PM10 limits, then EHP would be allowed to submit an amendment request to the District and the Energy Commission at that time. If that request is approved, EHP would identify any tendered ERC certificates that are surplus to the original PM10 offset requirements, and would request their return at full value.

EHP is proposing two modifications to the project's Conditions of Certification. The first is a change to Condition **AQ-21**, which would be modified to require the tendering, rather than the surrendering of ERC certificates to the District, prior to the commencement of operation. The second modification is the addition of new Condition **AQ-63**. This sets forth the procedure by which EHP would lower hourly, daily, and annual PM10 emission limits and thereby reduce the PM10 offset requirements set forth in Condition **AQ-21**. The changes and additions to Conditions of Certification are presented below.

On December 17, 2002, the SJVAPCD issued a revised approval to EHP's ATC reflecting the revision of PM10 emission rates and offset requirements as described above.

Commissioning Variance

Emissions

The requested commissioning emission limits are provided in Table 1, which shows the current hourly permit emissions limits and the requested commissioning emissions limits. No revised emission limits for PM10, SO2, or ammonia emissions have been requested.

**Table 1**
**Original and Proposed EHPP Commissioning Emission Limits**

| Pollutant | Turbine/HRSG Operating Emission Limits (lbs/hour)[a] | Turbine/HRSG Startup/Shutdown Emissions Limits (lbs/hour)[b] | Proposed Commissioning Emission Limits (Lbs/hour) |
|---|---|---|---|
| $NO_X$ | 15.8 | 76 | 400/185[c] |
| CO | 12.5 | 38 | 4,000/75[c] |
| VOC | 4.0 | --- | 200/20[c] |

a. From Condition of Certification AQ-15.
b. From Condition of Certification AQ-13.
c. Requested Phase I/Phase II emission limits.

Source: CEC 2000a, EHP 2002.

As can be seen in Table 1, the potential maximum hourly commissioning emissions far exceed current hourly permit limits, thus necessitating this amendment request.

The requested commissioning emission limits are reasonable in comparison to the commissioning emission limits that have been allowed recently for other licensed projects. Additionally, these emission limits would only be effective during the initial commissioning period. Phase I, referred to as the "Steam Blow/Boilout" phase, would occur at the start of initial commissioning. Phase II, referred to as the "Testing and Tuning" phase, would occur later during the initial commissioning period and would account for most of the time during initial commissioning. The initial commission is stated to last up to 500 hours within a 120-day period for each turbine. The maximum initial commissioning emissions estimated by the project owner are provided in Table 2.

**Table 2**
**Estimated Maximum Emissions During Commissioning (tons)**

| Phase | $NO_x$ | CO | VOC |
|---|---|---|---|
| I Steam Blow/Boilout | 18.3 | 11.2 | 1.0 |
| II Testing and Tuning | 49.0 | 24.2 | 3.7 |
| Total Commissioning | 67.3 | 35.5 | 4.8 |

Source: (EHP 2002)

It is possible that the actual emissions during commissioning will be substantially less than these conservative estimates.

Impact Analysis

The project owner provided a revised modeling analysis of the potential worst-case short-term NO2 and CO emission impacts. This modeling analysis did not use the normally accepted NOx-OLM (ozone limiting method) modeling approach to determine worst-case 1-hour NO2 impacts. Therefore, staff also conducted a NOx-OLM screening analysis. The project owner's CO modeling procedures and results were acceptable to Energy Commission staff. Table 3 provides the results of the project owner's and staff's modeling analyses.

**Table 3**
**Commissioning Emissions Short-Term Impact Modeling Results**

| Pollutant | Maximum Impact ($ug/m^3$) | Background ($ug/m^3$) | Total ($ug/m^3$) | Limiting AAQS ($ug/m^3$) |
|---|---|---|---|---|
| $NO_2$ | | | | |
| 1-hour (EHP) | 320[a] | 97 | 417 | 470 |
| 1-hour (staff) | 356[b] | 97 | 453 | 470 |
| CO | | | | |
| 1-hour | 4,418 | 2,941 | 7,359 | 23,000 |
| 8-hour | 1,746 | 2,222 | 3,968 | 10,000 |

a. Assumes 75% $NO_x$ conversion to $NO_2$.
b. $NO_x$-OLM screening value using an initial 0.25 $NO_2/NO_x$ ratio and a maximum 0.13 ppm ozone background.

Source: (Head 2003) and staff's modeling analysis.

This analysis shows that no exceedances of the short-term NO2 or CO standards are expected to occur as a result of the commissioning activities.

Staff reviewed the assumed exhaust conditions in the project owner's modeling files and found them to be reasonably consistent with the values used in other current siting cases. The stack velocity was somewhat higher than that used for other projects and the stack temperature was somewhat lower, which when their effects are combined they generally negate each other in terms of over- or underestimating project impacts. Staff performed NOx-OLM screening runs using the project owner assumed exhaust conditions (results shown in Table 3), and using the same stack conditions assumed for another recent siting case, and determined that the difference was minor and that both modeling runs showed total impacts (project impact plus background) to be lower than the State 1-hour ambient air quality standards.

Mitigation

For projects now being licensed, staff is requiring that the commissioning emissions be included in the emissions totals for the determination of offset requirements. This means that if a source has a quarterly emission limit to which they are applying emission offsets, the commissioning emissions would be assumed to be counted under that emissions limitation. However, this project was licensed prior to current staff procedures for counting commissioning emissions.

The current quarterly emissions limitations for the EHPP are approximately 35.6 tons for NOx, 8 tons for VOC, and 27.9 tons for CO. Equivalent 120-day emission totals would be approximately 47.4 tons for NOx, 10.7 tons of VOC and 37.2 tons of CO. Table 2 shows that the estimated commissioning VOC and CO emissions are less than the calculated quarterly limits extended to 120 days. The commissioning NOx emissions could cause an exceedance of quarterly emissions. The District's variance deals with this possibility by requiring NOx emission reduction credits (ERCs) in the amount of 20 percent of the excess determined to occur during the variance period be purchased and retired. The District's variance appears to use daily emission limits (condition 16f of the variance) as the basis for determining excess emissions. This approach is more conservative than using the quarterly emission limit approach, and may require the EHP to retire more NOx ERCs than is required for projects now being licensed.

No short-term NO2 impacts were found to occur from initial commissioning activities and any additional ERCs required for the project would result in a long-term net air quality improvement for the air basin. Therefore, staff accepts the District's Variance as providing acceptable NO2 mitigation for the commissioning emissions.

District's Variance

The District approved a commissioning emissions variance on November 13, 2002. Staff has found a number of potential issues regarding this variance. First, the District staff report, which was used as a basis for the excess emission value limits quoted in the variance, does not seem to properly quote the hourly emission limits for the project. Second, the variance exempts startup and shutdowns during the initial commissioning period from any and all emission limit requirements. Third, the variance does not allow excess PM10 emissions but does allow excess visible emissions. These issues will be discussed in order:

1. The staff report for the variance quoted non-startup hourly permitted emission limits for the two turbine/HRSGs to be 51 lbs/hr for NOx, 38 lbs/hr for CO and 5.2 lbs/hour for VOC. The current permit shows that the hourly permitted emission limits to be 31.6 lbs/hour for NOx, 25 lbs/hour for CO, and 8 lbs/hour for VOC.

2. The variance exempts startup and shutdown periods during initial commissioning from any emission limitations. The variance indicates that no violations of State ambient air quality standards are likely to occur. However, that cannot be confirmed without reasonable startup and shutdown emission limits.

3. The variance specifically notes that it allows only excess NOx, CO, VOC and visible emissions. However, any visible emissions, unless from a visible NOx plume, are an indication of excess PM10 emissions. No provisions for excess PM10 emissions, in terms of lbs/hour, have been granted.

Staff has sought clarification of these issues with the District. Michael Carrera of the District indicated that they used the project owner's normal operating hourly emission estimates provided in the variance request without modification. The project owner has stated that these values were probably provided in error, but that they do not affect the variance conditions.

Mr. Carrera also indicated that the District's intent was to not provide specific startup/shutdown emission limits during the commissioning period. However, in order to ensure that no ambient air quality standards are exceeded, staff recommends the addition of AQ-65, which limits the hourly NOx and CO emissions to 400 and 4,000 lbs/hour respectively (the maximum hourly emissions, regardless of operating mode, during commissioning).

Mr. Carrera indicated that the visible emissions variance was meant to cover excess particulate emissions, although not formally stated, and that the excess visible emissions were supposed to only occur early in Phase I of the initial commissioning. Staff does not normally request additional PM10 mitigation for commissioning emissions, so staff will not require any additional mitigation for PM10, however, staff would like the opportunity to review the Visible Emissions Evaluation data gathered during the commissioning period.

## Conclusions And Recommendations

ERC Tendering

Staff has analyzed the proposed changes to the EHPP Conditions of Certification and concludes that there will be no new emissions and no possibility of any significant air quality impacts associated with approving the request. Staff concludes that the proposed changes are based on new information that was not available during the original licensing proceedings. The proposed changes to the Conditions of Certification retain the intent of the original Commission Decision and Conditions of Certification. Therefore, staff recommends approval of the changes which are included below.

Commissioning Variance

EHPP requires higher emission limits during the initial commissioning period. EHP has already received a Variance from the District that covers commissioning emissions. Staff acknowledges the necessity for this amendment and accepts, with some minor changes, the Condition of Certification proposed by the project owner to address this issue. Staff also recommends an additional Condition of Certification to limit NOx and CO emissions during startup/shutdown events that occur during commissioning.

## Proposed New and Revisions to Existing Conditions of Certification

~~Strikethrough~~ indicates deleted text and <u>underline</u> indicates replacement or new text.

ERC Tendering

**AQ-21** Prior to <u>commencement of operation</u> ~~or upon startup~~ of S-3523-1-0, -2-0, & 3-0, emission offsets shall be <u>tendered</u> ~~surrendered~~ for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1, PM10 - Q1: 78,596 lb, Q2: 79,470 lb, Q3: 80,343 lb, and Q4: 80,343 lb; <u>and surrendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1,</u> SOx (as SO2) - Q1: 14,170 lb, Q2: 14,328 lb , Q3: 14,485 lb, and Q4: 14,485 lb; NOx (as NO2) - Q1: 65,353 lb, Q2: 66,079 lb, Q3: 66,805 lb, and Q4: 66,805 lb; and VOC - Q1: 10,967 lb, Q2: 11,089 lb, Q3: 11,211 lb, and Q4: 11,211 lb. [District Rule 2201]

**Verification**: The owner/operator shall submit copies of ERC<u>s</u> <u>tendered</u> <u>or</u> surrendered to the SJVUAPCD in the totals shown to the CPM prior to <u>commencement of operation</u> ~~or upon startup~~ of the CTGs or cooling tower.

<u>**AQ-63** The project owner may lower hourly, daily, and rolling average twelve-month PM10 emission limits in Conditions AQ-15, AQ-16, AQ-17, and AQ-18, and thereby reduce PM10 offset requirements set forth in AQ-21, based on actual PM10 emissions demonstrated during initial source tests. Revised emission limits shall be submitted to the District within 60 days after the last unit is initially source tested. The District will</u>

reflect revised limits in the permit to operate for the subject equipment. Any emission reduction credit certificates, or portions thereof, that were tendered to the District but are not needed to meet reduced PM10 offset requirements will be returned to the project owner at full value. The project owner shall indicate which emission reduction credit certificates are to be retired.

**Verification**: The project owner shall notify the CPM and District of any proposed changes in PM10 emission limits and indicate which ERC certificates are to be retired within 60 days after the last unit is initially source tested.

Commissioning Variance

**AQ-64** Relief granted by the San Joaquin Valley Air Pollution Control District Hearing Board on November 13, 2002 in Regular Variance Docket No. S-02-38R shall apply to Conditions of Certification AQ-5, AQ-13 through AQ-17, AQ-26, and AQ-27. The Project Owner shall comply with all requirements incorporated into the 19 conditions of this regular variance.

**Verification**: The Project Owner shall submit copies of all notifications and reports required under this regular variance to the CPM. The Project Owner shall notify the CPM within 5 days of any requested changes to this variance.

**AQ-65** During commissioning, emissions shall be limited to 400 lbs/hour of $NO_X$ and 4,000 lbs/hour of CO.

**Verification**: The Project Owner shall provide, within 24 hours of occurrence, notification to the CPM of any noncompliance with the commissioning startup/shutdown emission limits.

## REFERENCES


California Energy Commission (CEC). 2000a. Commission Decision – Elk Hills Power Project (99-AFC-1). December 2000.

California Energy Commission (CEC). 2000b. Final Staff Assessment - Elk Hills Power Plant Project (99-AFC-1). April 2000.

San Joaquin Valley Air Pollution Control District (District). 2002. Order Granting a Regular Variance. Docket No. S-02-38R. Granted on November 13, 2002.

Elk Hills Power, LLC (EHP). 2002. Petition for Post Certification Amendment and Changes – Air Quality. Elk Hills Power Plant (Docket No. 99-AFC-1C), December 2002.

Head. 2003. Commissioning Emissions Revised Modeling Files and Results Spreadsheet. Elk Hills Power Plant (Docket No. 99-AFC-1C), received by e-mail from Sara Head of ENSR on February 6, 2003.

The California ENERGY COMMISSION

# Elk Hills Power Plant Project

**Docket Number:** **99-AFC-01 (Application For Certification)**
**98-SIT-6 (NOI Exemption Proceeding)**

**99-AFC-1C (Compliance Proceeding)**

Committee Overseeing This Case:

Michal C. Moore, Commissioner
Presiding Member

Robert Pernell, Commissioner
Associate Member

Hearing Officer: Major Williams

### Key Dates

- **July 23, 2003** - Elk Hills Power Project declared as fully on line.
- **December 6, 2000** - Energy Commission certifies the application and grants the license for the Elk Hills Power Project.
- **November 20, 2000** - Revised Presiding Member's Proposed Decision (PMPD) issued.
- **August 25, 2000** - Presiding Member's Proposed Decision released.
- **April 28, 2000** - Staff issues Final Staff Assessment, Part 3 of 3.
- **February 18, 2000** - Staff issues Final Staff Assessment, Part 2 of 3.
- **January 6, 2000** - Staff issues Final Staff Assessment, Part 1 of 3.
- **November 19, 1999** - Staff issues Preliminary Staff Assessment.
- **June 9, 1999** - Second Data Adequacy Determination at a Commission Business Meeting.
- **March 31, 1999** - Energy Commission deems AFC Data Inadequate.
- **February 24, 1999** - Elk Hills Power, LLC files Application For Certification (AFC) for the Elk Hills Power Project (EHPP).
- **January 6, 1999** - California Energy Commission grants Elk Hills Power, LLC an exemption from the requirement to file a Notice of Intention (NOI) for construction of a power plant in California.
- **October 14, 1998** - Elk Hills Power, LLC files a Request for Jurisdictional Determination requesting a exemption from the requirement to file a Notice of Intention (NOI) for construction of a power plant in California.

### General Description of Project

The project as proposed by Elk Hills Power, LLC is a nominal 500 megawatt, natural gas-fired, combined cycle facility. The power plant would consist of two combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs) and exhaust stacks, and one steam turbine. It is a joint venture between Sempra Energy Resources and Occidental Energy Ventures of Elk Hills.

The Elk Hills Power Project (EHPP) will be located on 12 acres roughly in the center of the 74 square mile Elk Hills Oil and Gas Field operated by Occidental Energy Ventures of Elk Hills, Inc. (OEHI). The site is in western Kern County, California, approximately 25 miles west of Bakersfield, California. The project site is situated near the intersection of Elk Hills Road and Skyline Road.

A proposed new 9-mile bundled 230 kilovolt (kV) double circuit overhead transmission line will be built to interconnect either to the east at a new substation near Tupman, California, or north to the Midway substation near Buttonwillow, California. Natural gas will be supplied by a proposed new 2,500 foot, 10-inch supply pipeline owned and operated by OEHI.

Process water would be groundwater provided by the West Kern Water District (WKWD) and conveyed to the project site by a proposed new 9.8-mile, 16-inch supply pipeline. This pipeline would originate east of the power plant site at WKWD's water storage site located southwest of the intersection of the California Aqueduct and State Highway 119. Wastewater would be disposed of in proposed new disposal wells located 4 miles south of the power plant site and would be conveyed by a proposed new pipeline.

### Energy Commission Facility Certification Process

The Energy Commission is the lead agency under the California Environmental Quality Act (CEQA) and has a certified regulatory program under CEQA. Under its certified program, the Energy Commission is exempt from having to prepare an environmental impact report. Its certified program, however, does require environmental analysis of the project, including an analysis of alternatives and mitigation measures to minimize any significant adverse effect the project may have on the environment.

#### For Questions About This Siting Case Contact:

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