ORIGINAL

MORRISON & HECKER L.L.P.
ATTORNEYS AT LAW

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December 11, 2001

VIA HAND DELIVERY
Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Re: Allegheny Energy Supply Company, L.L.C. Docket No. L-00000AA – 01 - 0116

Dear Sir/Madam:

With this letter, AZURE files the original and 25 copies of the following exhibits for the December 13 and 14, 2001 hearings in this docket:

I-1 Pennsylvania Consent Order and Agreement dated October 16, 2000
I-2 Pennsylvania Consent Order and Agreement dated January 22, 2001
I-3 Cooling Cost comparison by Ms. Phyllis Fox
I-4 BDT: Air Cooled Turbine Exhaust Steam Condensers Worldwide Project Experience
I-5 The GEA Air Cooled Condenser
I-6 Massachusetts: Status of Power Plant Projects
I-7 Air-Cooled Heat Exchangers and Cooling Towers
I-8 Water Supply Issues Workshop Summary
I-17 Cumulative Impacts of Agriculture Evaporation Basins on Wildlife
I-18 Preliminary Cost Analysis of Wet/Dry/Hybrid Cooling Alternatives
I-19 12/6/01 letter from Gallagher & Kennedy transmitting dry cooling bids
I-20 Letter from Ken Schmidt to Laurie Woodall dated December 11, 2001

Sincerely,

MORRISON & HECKER L.L.P.

James D. Vieregg

James D. Vieregg

JDV:jd

Enclosures

Original and 25 copies filed this
date with Docket Control

COPY of the foregoing hand-delivered
this 11 day of December, 2001 to:

Jason D. Gellman, Esq.
Legal Division Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Michael M. Grant, Esq.
Gallagher & Kennedy
2575 East Camelback Road
Phoenix, AZ 85016

Todd C. Wiley, Esq.
Gallagher & Kennedy
2575 East Camelback Road
Phoenix, AZ 85016

Laurie A. Woodall, Esq.
Office of the Attorney General
Line Siting Committee Chair
1275 West Washington
Phoenix, AZ 85007

COPY of the foregoing mailed
this 11 day of December, 2001 to:

Marc D. Joseph, Esq.
Adams Broadwell Joseph & Cardozo
651 Gateway Boulevard
Suite 900
S. San Francisco, CA 94080

Mark R. Wolfe, Esq.
Adams Broadwell Joseph & Cardozo
651 Gateway Bulevard
Suite 900
S. San Francisco, CA 94080

Glenn R. Buckelew, Esq.
La Paz County Attorney
1320 Kofa Avenue
Parker, AZ 85344

JDV/jrd

Document1

EXHIBIT I - 1

ORIGINAL

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In The Matter Of:

Allegheny Energy Supply Company, LLC	:	Solid Waste Management Act
800 Cabin Hill Drive	:	
Greensburg, PA 15601	:	Community Environmental Project

CONSENT ORDER AND AGREEMENT

This Consent Order and Agreement is entered into this 16th day of October, 2000, by and between the Commonwealth of Pennsylvania, Department of Environmental Protection ("Department") and Allegheny Energy Supply Company, LLC ("AE Supply").

The Department has found and determined the following:

A. The Department is the agency with the duty and authority to administer and enforce the Solid Waste Management Act, Act of July 7, 1980, P.L. 380, *as amended*, 35 P.S. §§ 6018.101-6018.1003 ("SWMA"); Section 1917-A of the Administrative Code of 1929, Act of April 9, 1929, P.L. 177, *as amended*, 71 P.S. § 510-17 ("Administrative Code"); and, the rules and regulation ("rules and regulations") promulgated thereunder.

B. AE Supply is a Delaware corporation which is authorized to do business in Pennsylvania maintaining a business address of 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601.

C. AE Supply has been depositing flue gas desulfurization ("FGD") sludge generated by the Mitchell Power Station on the LaBelle Coal Preparation Plant property located in Luzerne Township, Fayette County ("Site") for beneficial use in land reclamation under authorization of Solid Waste Management Permit No. WMGR052D001 (the "Permit").

D. From October 20, 1999 to December 31, 1999, AE Supply statistically exceeded the allowable arsenic limit authorized by the Permit for FGD sludge at the Site, contrary to 25 Pa. Code § 287.612(b)(1).

E. AE Supply did not promptly report the exceedance to the Department as required by the Permit, contrary to 25 Pa. Code § 287.612(b)(1), but did voluntarily notify the Department of the exceedance and ceased further disposal at the Site.

F. The violations described in Paragraphs D and E constitute unlawful conduct under Section 610 of the SWMA, 35 P.S. § 6018.610; a statutory nuisance under Section 601 of the SWMA, 35 P.S. § 6018.601; and, subjects AE Supply to civil penalty liability by the Department under Section 605 of the SWMA, 35 P.S. § 6018.605.

G. The Department has calculated a civil penalty against AE Supply in the amount of Ten Thousand One Hundred Dollars ($10,100.00) for the violations described in Paragraphs D and E.

H. Pursuant to the Department's "Policy for the Acceptance of Community Environmental Projects in Lieu of a Portion of Civil Penalty Payments," AE Supply has proposed to the Department to pay Ten Thousand One Hundred Dollars ($10,100.00) to the Luzerne Township Supervisors to construct a pavilion, install electric service in the pavilion and provide security lighting for a proposed public access park in Luzerne Township leased from the Pennsylvania Fish Commission site adjacent to the Fredericktown Ferry as described in Attachment A ("Project").

I. Luzerne Township will be responsible for providing a contractor to perform the work and overseeing the development of the Project.

J. The Department has determined that the Project will provide recreational opportunities to the general public and is not something that AE Supply is otherwise legally required to do. The Department agrees that the value of the Project is approximately Ten Thousand One Hundred Dollars ($10,100.00) and that in consideration of the Project, the Department will allow AE Supply to pay for the Project in lieu of paying a civil penalty in the entire amount of Ten Thousand One Hundred Dollars ($10,100.00).

After full and complete negotiation of all matters set forth in this Consent Order and Agreement and upon mutual exchange of covenants contained herein, the parties desiring to avoid litigation and intending to be legally bound, it is hereby ORDERED by the Department and AGREED to by AE Supply as follows:

1. Authority. This Consent Order and Agreement is an Order of the Department authorized and issued pursuant to Sections 104(7) and 602 of the SWMA, 35 P.S. §§ 6018.104(7) and 6018.602; and, Section 1917-A of the Administrative Code, 71 P.S. § 510-17.

2. Findings.

a. AE Supply agrees that the findings in Paragraphs A through J are true and correct and, in any matter or proceeding involving AE Supply and the Department, AE Supply shall not challenge the accuracy or validity of these findings.

b. The parties do not authorize any other persons to use the findings in this Consent Order and Agreement in any matter or proceeding.

3. Civil Penalty Settlement. In resolution of the Department's claim for civil penalties for the violations set forth in Paragraphs D and E above, for the period from October 20, 1999 to

December 31, 1999, which the Department is authorized to assess under Section 605 of the SWMA, 35 P.S. § 6018.605, the Department assess a civil penalty of Ten Thousand One Hundred Dollars ($10,100.00). The Ten Thousand One Hundred Dollar ($10,100.00) civil penalty will be dedicated to the Project as provided for in Paragraph 4.

4. Community Environmental Project. AE Supply shall pay Luzerne Township its construction costs of the pavilion and installation of electrical service as described in Attachment A within thirty (30) days of the entry of this Consent Order and Agreement.

5. Tax Deductibility. AE Supply shall not deduct any costs incurred in connection with or in any way associated with the Project for any tax purpose or otherwise obtain favorable tax treatment for those costs. If requested to do so by the Department, AE Supply shall submit an affidavit of the corporate officer responsible for the financial affairs of AE Supply certifying that AE Supply has not deducted or otherwise obtained favorable tax treatment of any of the costs of the Community Environmental Project.

6. Publicity About the Project. AE Supply agrees that whenever it publicizes, in any way, the Project, it will state that the Project was undertaken as part of the settlement of an enforcement action with the Department.

7. Completion of Project. Within thirty (30) days of the completion of the Project, AE Supply shall submit to the Department an affidavit of the corporate official involved or associated with the Project. The affidavit shall contain certification from the Township that the Project is complete and a copy of the check transmitted to Luzerne Township.

8. Remedies. In the event that AE Supply fails to pay Luzerne Township for the Project, AE Supply shall pay a stipulated penalty in the amount of Ten Thousand One Hundred Dollars ($10,100.00). In either event, the Department may pursue any remedy available for

failure to pay a civil penalty, including the filing of this Agreement as a lien in any county in this Commonwealth.

9. Liability of AE Supply. AE Supply shall be liable for any violations of the Consent Order and Agreement, including those caused by, contributed to, or allowed by its officers, agents, or employees. AE Supply also shall be liable for any violation of this Consent Order and Agreement caused by, contributed to, or allowed by its successors and assigns.

10. Entire Agreement. This Consent Order and Agreement shall constitute the entire integrated agreement of the parties. No prior or contemporaneous communications or prior drafts shall be relevant or admissible for purposes of determining the meaning or intent of any provisions herein in any litigation or any other proceeding.

11. Attorney Fees. The parties shall bear their respective attorney fees, expenses and other costs in the prosecution or defense of this matter or any related matters, arising prior to execution of this Consent Order and Agreement.

12. Modifications. No changes, additions, modifications, or amendments of this Consent Order and Agreement shall be effective unless they are set out in writing and signed by the parties hereto.

IN WITNESS WHEREOF, the parties hereto have caused this Consent Order and Agreement to be executed by their duly authorized representatives. The undersigned representatives of AE Supply certify under penalty of law, as provided by 18 Pa. C.S. § 4904, that they are authorized to execute this Consent Order and Agreement on behalf of AE Supply; that AE Supply consents to the entry of this Consent Order and Agreement as a final ORDER of the Department; and that AE Supply hereby knowingly waives its rights to appeal this Consent Order and Agreement and to challenge its content or validity, which rights may be available under Section 4 of the Environmental Hearing Board Act, the Act of July 13, 1988, P.L. 530, No. 1988-94, 35 P.S. § 7514; the Administrative Agency Law, 2 Pa. C.S. § 103(a) and Chapters 5A and 7A; or any other provision of law. Signature by AE Supply's attorney certifies only that the agreement has been signed after consulting with counsel.

FOR ALLEGHENY ENERGY
SUPPLY COMPANY, LLC:

____
David C. Benson
Vice President
Production & Sales

____
Norbert J. Smith
Attorney for AE Supply

FOR THE COMMONWEALTH OF
PENNSYLVANIA, DEPARTMENT OF
ENVIRONMENTAL PROTECTION:

____
Anthony D. Orlando
Regional Manager
Bureau of Waste Management

______________________________ 10/11/2000
Kenneth T. Bowman
Assistant Regional Counsel

CERTIFIED MAIL

Allegheny Energy Supply
an Allegheny Energy company

Projects Division
800 Cabin Hill Drive
Greensburg, PA 15601-1689
(724) 837-3000

October 5, 2000

Mr. Anthony D. Orlando
Regional Manager
Waste Management
PA Department of Environmental Protection
400 Waterfront Drive
Pittsburgh, PA 15222-4745

RE: Mitchell Power Station
Permit No. WMGR052D001
Consent Order and Agreement
Community Project in Lieu of Civil Penalty Payment

Dear Mr. Orlando:

As requested, enclosed are signed copies of the referenced Consent Order and Agreement. Once we receive the final copy of this document, we will send a letter transmitting the check to Luzerne Township.

Your office will receive a copy of both the letter and check.

If you have any questions, please contact me at (724) 830-5890.

Sincerely,

Nancy D. Pointon

Nancy D. Pointon

NDP/sjp

Enclosures

cc: Mr. Ken Bowman - PADEP (Pgh.)

EXHIBIT I - 2 ORIGINAL

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of:

Allegheny Energy Supply Company, LLC	:	Air Quality
800 Cabin Hill Drive	:	Visible Emissions Violations
Greensburg, PA. 15601-1689	:	25 Pa. Code §123.41

CONSENT ORDER AND AGREEMENT

This Consent Order and Agreement is entered into this 22nd day of January, 2004 by and between the Commonwealth of Pennsylvania, Department of Environmental Protection (hereinafter "Department"), and Allegheny Energy Supply Company, LLC (hereinafter "Allegheny Energy").

The Department has found and determined the following:

A. The Department is the agency with the duty and authority to administer and enforce the Air Pollution Control Act, Act of January 8, 1960, P.L. 2119 (1959), as amended, 35 P.S. §§ 4001-4015 ("Air Pollution Control Act"); Section 1917-A of the Administrative Code of 1929, Act of April 9, 1929, P.L. 177, as amended, 71 P.S. § 510-17 ("Administrative Code"); and the rules and regulations ("rules and regulations") promulgated thereunder.

B. Allegheny Energy is a ~~Pennsylvania~~ Delaware limited liability corporation with a mailing address of 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601-1689.

C. Allegheny Energy owns and operates The Mitchell Power Station located in Union Township, Washington County, Pennsylvania (hereinafter "Site"). Among other things, Allegheny Energy operates coal fired boiler number 33 at the Site which provides steam for electricity generation unit number 3. Boiler number 33 exhausts through a single 375 foot stack. Allegheny Energy operates the Site pursuant to Air Quality Permit number TV 63-016.

D. Visible emissions from the Site are regulated by 25 Pa. Code § 123.41

which states:

> A person may not permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following:
>
> (1) Equal to or greater than 20% for a period or periods aggregating more than 3 minutes in any 1 hour.
> (2) Equal to or greater than 60% at any time.

E. The Department conducted an opacity study of the 375 foot stack at the facility. Visible emission observation records of this stack were documented on October 19, 1999, November 5, 1999 and November 9, 1999. On October 19, 1999, November 5, 1999 and November 9, 1999 Allegheny Energy emitted visible air contaminants with an opacity greater than 20% for more than 3 minutes in one hour, in violation of 25 Pa. Code § 123.41(1).

F. The violations described in Paragraph E, above, constitute unlawful conduct under Section 8 of the Air Pollution Control Act, 35 P.S. § 4013, and subject Allegheny Energy to civil penalty liability under Section 9.1 of the Air Pollution Control Act, 35 P.S. § 4009.1.

G. Allegheny Energy has developed and will implement a testing and study plan designed toward resolving the opacity problem at the facility. Allegheny Energy plans to spend in excess of $80,000.00 on the testing.

After full and complete negotiation of all matters set forth in this Consent Order and Agreement and upon mutual exchange of covenants contained herein, the parties desiring to avoid litigation and intending to be legally bound, it is hereby ORDERED by the Department and agreed to by Allegheny Energy as follows:

1. Authority. This Consent Order and Agreement is an Order of the Department authorized and issued pursuant to §§ 4(9)(i) and 10.1 of the Air Pollution Control Act, 35 P.S. § 4004(9)(i) and 4010.1, and § 1917-A of the Administrative Code, 71 P.S. § 510-17.

2. Findings.

a. Allegheny Energy agrees that the findings in Paragraphs A through G are true and correct and, in any matter or proceeding involving Allegheny Energy and the

Department, Allegheny Energy shall not challenge the accuracy or validity of these findings.

b. The parties do not authorize any other persons to use the findings in this Consent Order and Agreement in any matter or proceeding.

3. Corrective Action

Allegheny Energy has begun an engineering study of the opacity problem and is committed to finding the cause and solution to the problem.

a. Allegheny Energy has contracted URS-Radian to conduct a study of Boiler #33 to determine the cause of the intermittent opacity. USR-Radian conducted stack testing at the facility during the week of July 24, 2000. Testing was done with the unit operating both at reduced load and close to full load with varying amounts of excess combustion air. Preliminary results of this testing indicates that the primary cause of the plume opacity is sulfuric acid mist.

b. On or before January 2001 Allegheny Energy will submit plans to the Department of Energy for a joint project with CONSOL Energy to investigate a multi-pollutant control technology. This project will involve slip-stream testing of flue gas to reduce emissions that may contribute to a visible plume and also reduce other emissions. This project will begin as soon as possible after funding has been approved by the Department of Energy.

c. Allegheny Energy shall use sound engineering and operational procedures to prevent opacity violations during this twelve-month engineering evaluation.

d. Allegheny Energy will submit quarterly progress reports regarding the engineering evaluation to the Department beginning three (3) months from the date of this Consent Order and Agreement.

4. Civil Penalty Settlement

The Department has agreed to waive civil penalties for opacity violations occurring during the twelve (12) months following the date of this COA, so long as the requirements of the COA are strictly complied with by Allegheny Energy.

5. Stipulated Civil Penalties.

a. In the event Allegheny Energy fails to comply in a timely manner with any term or provision of this Consent Order and Agreement, Allegheny Energy shall be in violation of this Consent Order and Agreement and, in addition to other applicable remedies, shall pay a civil penalty in the amount of $750.00 per day for each violation of this COA.

b. Stipulated civil penalty payments shall be payable monthly on or before the fifteenth day of each succeeding month. The payments shall be made by corporate check or the like made payable to the "Commonwealth of Pennsylvania, Clean Air Fund" and sent to the Air Quality Program Manager, Department of Environmental Protection, 400 Waterfront Drive, Pittsburgh, PA 15222-4745.

c. Any payment under this paragraph shall neither waive Allegheny Energy's duty to meet its obligations under this Consent Order and Agreement nor preclude the Department from commencing an action to compel Allegheny Energy's compliance with the terms and conditions of this Consent Order and Agreement. The payment resolves only Allegheny Energy's liability for civil penalties arising from the violation of this Consent Order and Agreement for which the payment is made.

d. Stipulated civil penalties shall be due automatically and without notice.

6. Additional Remedies.

a. In the event Allegheny Energy fails to comply with any provision of this Consent Order and Agreement, the Department may, in addition to the remedies prescribed herein, pursue any remedy available for a violation of an order of the Department, including an action to enforce this Consent Order and Agreement.

b. The remedies provided by this paragraph and Paragraph 5 (Stipulated Civil Penalties) are cumulative and the exercise of one does not preclude the exercise of any other. The failure of the Department to pursue any remedy shall not be deemed to be a waiver of that remedy. The payment of a stipulated civil penalty, however, shall preclude any further assessment of civil penalties for the violation for which the stipulated civil penalty is paid.

7. Reservation of Rights. The Department reserves the right to require additional measures to achieve compliance with applicable law. Allegheny Energy reserves the

right to challenge any action which the Department may take to require those measures.

8. Liability of Operator. Allegheny Energy shall be liable for any violations of the Consent Order and Agreement, including those caused by, contributed to, or allowed by its officers, agents, employees, or contractors. Allegheny Energy also shall be liable for any violation of this Consent Order and Agreement caused by, contributed to, or allowed by its successors and assigns.

9. Transfer of Site.

a. The duties and obligations under this Consent Order and Agreement shall not be modified, diminished, terminated or otherwise altered by the transfer of any legal or equitable interest in the Site or any part thereof.

b. If Allegheny Energy intends to transfer any legal or equitable interest in the Site which is affected by this Consent Order and Agreement, Allegheny Energy shall serve a copy of this Consent Order and Agreement upon the prospective transferee of the legal and equitable interest at least thirty (30) days prior to the contemplated transfer and shall simultaneously inform the Southwest Regional Office of the Department of such intent.

10. Correspondence with Department. All correspondence with the Department concerning this Consent Order and Agreement shall be addressed to:

Joseph P. Pezze
Air Quality Program Manager
Department of Environmental Protection
400 Waterfront Drive
Pittsburgh, PA 15222-4745
Phone: (412) 442-4000
Fax: (412) 442-4194

11. Correspondence with Allegheny Energy. All correspondence with Allegheny Energy concerning this Consent Order and Agreement shall be addressed to:

Randy Cain, Environmental Specialist
Allegheny Energy Supply Company LLC
800 Cabin Hill Drive
Greensburg, PA. 15601-1689
Phone: (724) 837-3000
Fax : (724) 838-6464

Allegheny Energy shall notify the Department whenever there is a change in the contact person's name, title, or address. Service of any notice or any legal process for any purpose under this Consent Order and Agreement, including its enforcement, may be made by mailing a copy by first class mail to the above address.

12. Force Majeure.

a. In the event that Allegheny Energy is prevented from complying in a timely manner with any time limit imposed in this Consent Order and Agreement solely because of a strike, fire, flood, act of God, or other circumstances beyond Allegheny Energy's control and which Allegheny Energy, by the exercise of all reasonable diligence, is unable to prevent, then Allegheny Energy may petition the Department for an extension of time. An increase in the cost of performing the obligations set forth in this Consent Order and Agreement shall not constitute circumstances beyond Allegheny Energy's control. Allegheny Energy's economic inability to comply with any of the obligations of this Consent Order and Agreement shall not be grounds for any extension of time.

b. Allegheny Energy shall only be entitled to the benefits of this paragraph if it notifies the Department within five (5) working days by telephone and within ten (10) working days in writing of the date it becomes aware or reasonably should have become aware of the event impeding performance. The written submission shall include all necessary documentation, as well as a notarized affidavit from an authorized individual specifying the reasons for the delay, the expected duration of the delay, and the efforts which have been made and are being made by Allegheny Energy to mitigate the effects of the event and to minimize the length of the delay. The initial written submission may be supplemented within 10 working days of its submission. Allegheny Energy's failure to comply with the requirements of this paragraph specifically and in a timely fashion shall render this paragraph null and of no effect as to the particular incident involved.

c. The Department will decide whether to grant all or part of the extension requested on the basis of all documentation submitted by Allegheny Energy and other information available to the Department. In any subsequent litigation, the operator shall have the burden of proving that the Department's refusal to grant the requested extension was an abuse of discretion based upon the information then available to it.

13. Severability. The paragraphs of this Consent Order and Agreement shall be severable and should any part hereof be declared invalid or unenforceable, the remainder shall continue in full force and effect between the parties.

14. Entire Agreement. This Consent Order and Agreement shall constitute the entire integrated agreement of the parties. No prior or contemporaneous communications or prior drafts shall be relevant or admissible for purposes of determining the meaning or intent of any provisions herein in any litigation or any other proceeding.

15. Attorney Fees. The parties shall bear their respective attorney fees, expenses and other costs in the prosecution or defense of this matter or any related matters, arising prior to execution of this Consent Order and Agreement.

16. Modifications. No changes, additions, modifications, or amendments of this Consent Order and Agreement shall be effective unless they are set-out in writing and signed by the parties hereto.

17. Titles. A title used at the beginning of any paragraph of this Consent Order and Agreement may be used to aid in the construction of that paragraph, but shall not be treated as controlling.

19. Decisions under Consent Order. Any decision which the Department makes under the provisions of this Consent Order and Agreement is intended to be neither a final action under 25 Pa. Code §1021.2, nor an Adjudication under 2 Pa. C.S. § 101. Any objection which Allegheny Energy may have to the decision will be preserved until the Department enforces this Consent Order and Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Consent Order and Agreement to be executed by their duly authorized representatives. The undersigned representatives of Allegheny Energy certify under penalty of law, as provided by 18 Pa. C.S. § 4904, that they are authorized to execute this Consent Order and Agreement on behalf of Allegheny Energy; that Allegheny Energy consents to the entry of this Consent Order and Agreement as a final ORDER of the Department; and that Allegheny Energy hereby knowingly waives its rights to appeal this Consent Order and Agreement and to challenge its content or validity, which rights may be available under § 4 of the Environmental Hearing Board Act, the Act of July 13, 1988, P.L. 530, No. 1988-94, 35 P.S. § 7514; the Administrative Agency Law, 2 Pa. C.S. § 103(a) and Chapters 5A and 7A; or any other provision of law. [Signature by Allegheny Energy's attorney certifies only that the agreement has been signed after consulting with counsel. If Allegheny Energy chooses not to consult with counsel before signing, please initial and write the word "waived" on the attorney signature block.]

FOR ALLEGHENY ENERGY
SUPPLY COMPANY, LLC

Signature
Name Peter J. Skrgic

President

Signature
Name Patricia J. Clark

Assistant Secretary

Signature
Name Norbert J. Smith

Attorney for Allegheny Energy
Supply Company, LLC

COMMONWEALTH OF
PENNSYLVANIA, DEPARTMENT
OF ENVIRONMENTAL
PROTECTION:

Joseph P. Pezze
Regional Air Quality Program

Approved as to legality and form:

Michael J. Heilman
Assistant Counsel

EXHIBIT I - 3

ORIGINAL

COST ($ million)

	Wet	Dry with Ponds	Basis
<u>COOLING CIRCUIT</u>			
Surface Condenser	4.6		Vendor Quote
Circulating Water Pump	2.6		Vendor Quote
Cooling Tower	5.1		Vendor Quote
Air Cooled Condenser		30.1	Vendor Quote
Installation & Out of Scope	9.2	8.0	Vendor Quote
Auxiliary Cooling Tower		1.0	Engineering Estimate
Steam Turbine		-11.3	PEACE output
<u>AUXILIARIES</u>			
Wells	0.6		Engineering estimate
Pumps	0.1		Engineering estimate
Pipeline	1.0		Engineering estimate
Tanks	0.5	1.0	Engineering estimate
Land for water rights	9.0		Geraghty testimony
Evaporation Ponds	6.0		Geraghty testimony
Water Treatment	4.5	0.5	Engineering estimate for dual media filter and reverse osmosis
TOTAL COST	43.2	29.3	

75125.0002::ODMA\PCDOCS\PHXDOCS\142263\1

ORIGINAL

EXHIBIT I - 4

BDT
ENGINEERING
Balcke-Dürr, Inc.
(September 2001)

AIR COOLED TURBINE EXHAUST STEAM CONDENSERS WORLDWIDE PROJECT EXPERIENCE

Client	Location	Steam Flow lb / h	Back Pressure	Installed
Stone & Webster / KeySpan	Ravenswood, Queens, NY	612,900	5.41"HgA	Engineering
Parsons E&C / Tractebel	Chehalis, WA	1,080,000	1.98"HgA	Engineering
Mirant Corporation	Las Vegas, NV	1,450,000	10.0"HgA	Construction
Asea Brown Boveri (ABB)	Bellingham, MA	2 x 520,000	2.50"HgA	Construction
ABB	Midlothian (Ext), TX	2 x 500,000	2.40"HgA	Commissioning
ABB	Lake Road, CT	3 x 520,000	2.50"HgA	Commissioning
ABB	Hays, TX	2 x 500,000	2.40"HgA	2001
ABB	Blackstone, MA	2 x 540,000	2.20"HgA	Commissioning
Electricite de France (EDF)	Rio Bravo, Mexico	1,100,000	3.0"HgA	2001
ABB	Midlothian, TX	4 x 500,000	2.40"HgA	2000
Mitsubishi Heavy Industries	Chihuahua, Mexico	970,000	2.76"HgA	2001
ABB	Monterrey, Mexico	2 x 545,000	2.24"HgA	2000
ABB	Enfield, England	804,400	2.1 "HgA	1999
Thomassen Power Systems Doga / Mission Energy	Esenyurt, Turkey	390,000	7.5 "HgA	1998
EPA Taiwan/ Chung-Hsin Electric & Machinery	Hsinchu, Taiwan	205,955	4.43 "HgA	1998
EPA Taiwan/ Chung-Hsin Electric & Machinery	Pali, Taiwan	308,577	4.43 "HgA	2000
ESP Geko / HKW Feldberg	Feldberg,Germany	44,100	5.9 "HgA	1997
ESP Geko / HKW	Dresden, Germany	63,900	35.5 "HgA	1997
ML Ratingen / MHKW Pirmasens (Single Row)	Germany	117,200	3.3 "HgA	1997
ABB Enertech AG / KVA Niederumen	Switzerland	35,000	2.9 "HgA	1996

405 N. REO STREET, TAMPA, FL 33609 USA Phone: (813) 289-1516 Fax: (813) 289-9385

BDT
ENGINEERING
Balcke-Dürr, Inc.
(September 2001)

AIR COOLED TURBINE EXHAUST STEAM CONDENSERS WORLDWIDE PROJECT EXPERIENCE

Client	Location	Steam Flow lb / h	Back Pressure	Installed
D.B. Anlagen / VERA Hamburg (Single Row)	Germany	33,000	5.9 "HgA	1996
Bechtel	Crockett, CA	608,000	2.0 "HgA	1996
Caliqua Basel / KVA Gamsen	Switzerland	38,800	2.9 "HgA	1996
Statwerke Kiel / MVA Kiel	Germany	45,200	103 "HgA	1996
Siemens KWU / AEZ Kreis Wesel	Germany	165,300	2.9 "HgA	1996
Siemens KWU / SBA Furth (Single Row)	Germany	104,100	4.1 "HgA	1996
AVI Twente, Hengelo / Twente	Netherlands	194,400	2.5 "HgA	1996
Billings Generation	Billings, MT	463,696	7.5"HgA	1995
Stork Ketels / Wapenveld	Netherlands	103,200	2.9 "HgA	1995
NEMA Netzschkau / Izmit (Single Row)	Turkey	43,000	2.3 "HgA	1995
Blohm & Voss / SAVA Brunsbuttel (Single Row)	Germany	30,900	3.5 "HgA	1995
ML Ratingen / MVA Offenbach (Single Row)	Germany	75,000	3.5 "HgA	1995
ESP Heinzwerke / Sulzbach-Rosenberg	Germany	41,400	5.9 "HgA	1994
Caliqua Basel / KVA Thurgau	Switzerland	130,100	14.7 "HgA	1994
Bechtel	Rochester, MA	220,250	3.5"HgA	1993
PowerGen/Siemens	United Kingdom	1,877,900	2.7"HgA	1993
Krupp Stahl /	Germany	36,400	38 "HgA	1993

BDT
ENGINEERING
Balcke-Dürr, Inc.
(September 2001)

AIR COOLED TURBINE EXHAUST STEAM CONDENSERS WORLDWIDE PROJECT EXPERIENCE

Client	Location	Steam Flow lb / h	Back Pressure	Installed
Bochum				
MAN GHH / GSB Ebenhausen	Germany	70,500	6.2 "HgA	1993
ABB Numberg / AVA Augsburg	Germany	122,700	3.5 "HgA	1993
Blom & Voss Batam	Indonesia	57,500	13.3 "HgA	1992
CRS Sirrine	Lowell, MA	160,000	3.25"HgA	1991
CNF Constructors	Fitchburg, MA	127,000	3.5"HgA	1991
Indeck Energy	Silver Springs, NY	120,000	2.5"HgA	1990
Rutgerwerke	W. Germany	88,000	5.0"HgA	1990
Lurgi MSW Bazenheid	Switzerland	3,100	3.5"HgA	1989
Siemens/MWS Cogen. Weissenhom	W. Germany	83,000	4.5"HgA	1989
Chemische Fabrik Budenheim	W. Germany	6,000	1.8"HgA	1989
Blohm and Voss MSW,Beselich	W. Germany	13,200	3.0"HgA	1988
Blohm and Voss MSW Pinneberg	W. Germany	68,000	6.0"HgA	1987
ABB Baden, Kabul	Afghanistan	243,000	3.5"HgA	1987
SERT MSW Harelbeke	Belgium	44,000	1.5"HgA	1985
Stadtwerke Frankfurt for MSW Frankfurt	Germany	55,000	15.0"HgA	1985
BBC Mannheim (ABB), Touss Unit 4 150 MW Power Station	Iran	792,000	8.0"HgA	1984
BBC Mannheim, Touss	Iran	792,000	8.0"HgA	1984

BDT
ENGINEERING
Balcke-Dürr, Inc.
(September 2001)

AIR COOLED TURBINE EXHAUST STEAM CONDENSERS WORLDWIDE PROJECT EXPERIENCE

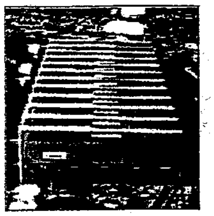
Client	Location	Steam Flow lb / h	Back Pressure	Installed
Unit 3 150 MW Power Station				
BBC Mannheim for MWS/Geiselbullach	Germany	72,600	4.0"HgA	1984
BBC Mannheim MSW Neustadt	W. Germany	57,200	3.6"HgA	1984
Kringlen MSW Linthgebiet	Switzerland	58,700	4.0"HgA	1983
BBC Mannheim, Touss Unit 2 150 MW Power Station	Iran	792,000	8.0"HgA	1983
BBC Mannheim, Touss Unit 1 150 MW Power Station	Iran	792,000	8.0"HgA	1983
Standard Messo MSW Stapelfeld	West Germany	17,600	2.7"HgA	1982
Techn. Werke Ludwigshafen	West Germany	39,600	3.0"HgA	1982
Babcock Krauss Maffei Imperial, MSW Burgau	West Germany	26,400	6.0"HgA	1982
Widmer + Ernst MSW Ingolstadt	West Germany	57,900	3.7"HgA	1982
B C Berlin, MSW Krefeld	West Germany	130,500	5.5"HgA	1981
Stork Boilers	Netherlands	90,200	3"HgA	1981
Goepfert + Reimer, Iserlon	West Germany	110,000	15"HgA	1980
G H, Hattingen	West Germany	71,500	5.5"Hg	1980
Cabot	West Germany	29,900	6"HgA	1979
Mura Biel	Switzerland	24,200	19.5"HgA	1978
Didier	Netherlands	4,600	10.5"HgA	1977
Widmer + Ernst, Hamburg	West Germany	178,200	3.6"HgA	1976
SSK v. Schaewen	West Germany	17,800	30"HgA	1976

BDT
ENGINEERING
Balcke-Dürr, Inc.
(September 2001)

AIR COOLED TURBINE EXHAUST STEAM CONDENSERS
WORLDWIDE PROJECT EXPERIENCE

Client	Location	Steam Flow lb / h	Back Pressure	Installed
City of Frankfurt	West Germany	52,800	15"HgA	1976
B A S F, Antwerpen	Belgium	19,100	27"HgA	1976
DuPont	West Germany	4,400	30"HgA	1976
Borsig, Ruhrgas	West Germany	118,800	6.6"HgA	1975
Stadt Bremerhaven	West Germany	176,000	14"HgA	1975
Krupp	Poland	44,000	24"HgA	1974
DuPont	West Germany	7,300	30"HgA	1974
V K W, Goppingen	West Germany	92,400	4.5"HgA	1974
DuPont	West Germany	6,400	30"HgA	1972
AEG-Kanis Turbines Hamburg	West Germany	110,000	4"HgA	1972
G H, Rottka	West Germany	44,000	3"HgA	1971
K H D, Koln	West Germany	7,000	12"HgA	1971
Bechtel/Canada Kwinana	Australia	79,000	6"HgA	1969
Stadtwerke Solingen	West Germany	39,000	4.5"HgA	1969
Glanzstoff Koln	West Germany	28,600	30"HgA	1968
Wirus Werke	West Germany	4,600	30"HgA	1968
Saline Ludwigshafen	West Germany	700	30"HgA	1967
AEG-Kanis, Cabot	West Germany	55,000	23"HgA	1966
KEW/Werhohl	West Germany	22,000	33"HgA	1961

405 N. REO STREET, TAMPA, FL 33609 USA Phone: (813) 289-1516 Fax: (813) 289-9385



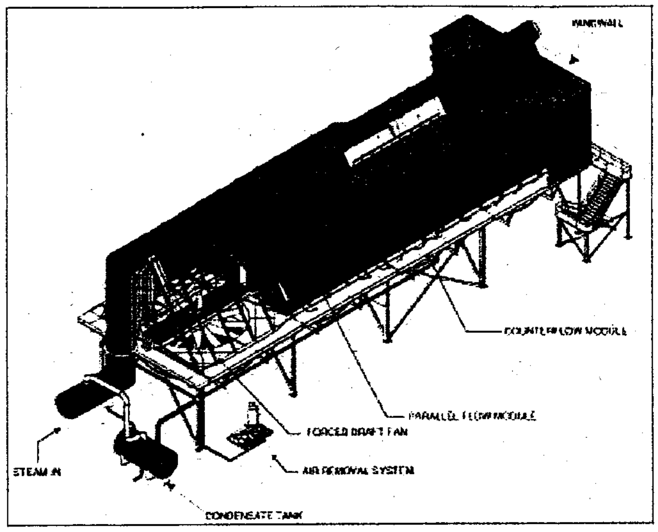
Linden Cogeneration Plant Linden, NJ

Installation List

Photos

Fin Tube Cleaning System

The GEA Air Cooled Condenser



The GEA air-cooled condenser is comprised of fin tube bundles grouped together into modules and mounted in an A-frame configuration on a steel support structure. Vertical and horizontal configurations are also available.

GEA employs a two stage, single pressure condensing process to achieve efficient and reliable condensation. In this process, the steam is first ducted from the steam turbine to the air-cooled condenser where it enters parallel flow fin tube bundles from the top. The steam is only partly condensed in the parallel flow modules and the remaining steam is ducted in a lower header to counterflow fin tube bundles. The steam enters from the bottom and rises in the fin tubes to a point where condensation is completed. Non-condensibles are drawn off above this point by ejection equipment. The condensate drains by gravity to a condensate tank and is then sent back to the feedwater system to be recycled.

GEA

GEA Power Cooling Systems, Inc.

HOMEPAGE

Direct Air Cooled Condenser Installations

STATION OWNER (A/E)	SIZE [Mw(e)] (1)	STEAM FLOW [Lb/Hr]	TURBINE BP [IN HgA]	DESIGN TEMP. [deg.F]	YEAR	REMARKS
Neil Simpson I Station Black Hills Power & Light Co. Gillette, WY (Stearns Roger)	20	167,550	4.5	75	1968	Coal Fired Plant
Norton P. Potter Gen. Station Braintree Electric Light Dept. Braintree, MA (R. W. Beck)	20	190,000	3.5	50	1975	Combined Cycle
Benecia Refinery Exxon Company, U.S.A. Benecia, CA	NA	48,950	9.5	100	1975	
Wyodak Station Black Hills Power & Light Co. and Pacific Power & Light Co. Gillette, WY (Stone & Webster)	330	1,884,800	6.0	66	1977	Coal Fired Plant
Beluga Unit No. 8 Chugach Electric Assoc., Inc. Beluga, AK (Burns & Roe)	65	478,400	5.6	35	1979	Combined Cycle
Gerber Cogeneration Plant Pacific Gas & Electric Gerber, CA (Mechanical Technology Inc.)	3.7	52,030	2.03	48	1981	Cogeneration

NAS North Island Cogen Plant **Sithe Energies, Inc.** Coronado, CA	4.0	65,000	5.0	70	1984	Cogeneration (Turnkey)
NTC Cogen Plant **Sithe Energies, Inc.** San Diego, CA	2.6	40,000	5.0	70	1984	Cogeneration (Turnkey)
Chinese Station **Pacific Ultrapower** China Camp, CA (Ultrasystems Eng. & Const.)	22.4	181,880	6.0	97	1984	Waste Wood
Dutchess County RRF Poughkeepsie, NY (Pennsylvannia Engineering)	7.5	50,340	4.0	79	1985	WTE
Sherman Station **Wheelabrator Sherman Energy Co.** Sherman Station, ME (Atlantic Gulf)	20	125,450	2.0	43	1985	Waste Wood
Olmsted County WTE Facility Rochester, MN (HDR Techserv)	1	42,000	5.5	80	1985	WTE
Chicago Northwest WTE Facility **City of Chicago** Chicago, IL	1	42,000	15 PSIG	90	1986	WTE
SEMASS WTE Facility **American Ref-Fuel** Rochester, MA (Bechtel, Inc.)	54	407,500	3.5	59	1986	WTE

Haverhill Resource Rec. Facility **Ogden Martin Sys. of Haverhill** Haverhill, MA (Stone & Webster)	46.9	351,830	5.0	85	1987	WTE
Hazelton Cogeneration Facility **Continental Energy Associates** Hazelton, PA (Brown Boveri Energy Systems)	67.5	420,000	3.7	47	1987	Cogeneration (Turnkey)
Grumman **TBG Cogen** Bethpage, NY (General Electric)	13	105,700	5.4	59	1988	Cogeneration
Cochrane Station **Northland Power** Cochrane, Ontario, Canada (Volcano, Inc.)	10.5	90,000	3.0	60	1988	Cogeneration
North Branch Power Station **Energy America Southeast** North Branch, WV (Fru-Con Construction Corp.)	80	622,000	7.0	90	1989	Coal Fired Plant
Sayreville Cogen Project **Intercontinental Energy Co.** Sayreville, NJ (Westinghouse Electric Corp.)	100	714,900	3.0	59	1989	Cogeneration
Bellingham Cogen Project **Intercontinental Energy Co.** Bellingham, MA (Westinghouse Electric Corp.)	100	714,900	3.0	59	1989	Cogeneration
Spokane Resource Rec. Facility **Wheelabrator Spokane Inc.** Spokane, WA (Clark-Kenith Inc.)	26	153,950	2.0	47	1989	WTE (Turnkey)
Exeter Energy L. P. Project **Oxford Energy** Sterling, CT	30	196,000	2.9	75	1989	PAC Systemä
Peel Energy From Waste **Peel Resources Recovery, Inc.** Brampton, Ontario, Canada (SNC Services, Ltd.)	10	88,750	4.5	68	1990	WTE

Nipigon Power Plant **Transcanada Pipelines** Nipigon, Ontario, Canada (SNC Services, Ltd.)	15	169,000	3.0	59	1990	Cogeneration
Linden Cogeneration Project **Cogen Technologies, Inc.** Linden, NJ (Ebasco Constructors, Inc.)	285	1,911,000	2.44	54	1990	Cogeneration
Maalaea Unit #15 **Maui Electric Company, Ltd.** Maui, Hawaii (Stone & Webster)	20	158,250	6.0	95	1990	Combined Cycle
Norcon - Welsh Plant **Falcon Seaboard** North East, PA (Zurn/Nepco, Inc.)	20	150,000	2.5	55	1990	Cogeneration
University of Alaska University of Alaska, Fairbanks Fairbanks, AK	10	46,000	6.0	82	1991	Cogeneration
Union County RRF **Ogden Martins Sys. of Union County** Union, NJ (Stone & Webster)	50	357,000	8.0	94	1991	WTE (Turnkey)
Saranac Energy Plant **Falcon Seaboard** Saranac, NY (Zurn/Nepco, Inc.)	80	736,800	5.0	90	1992	Cogeneration
Onondaga County RRF **Ogden Martins Sys. of Onondaga Co.** Onondaga, NY (Stone & Webster)	50	258,000	3.0	70	1992	WTE (Turnkey)
Neil Simpson II Station **Black Hills Power & Light Co.** Gillette, WY (Black & Veatch)	80	548,200	6.0	66	1992	Coal Fired Plant (Turnkey)
Gordonsville Plant **Mission Energy** Gordonsville, VA (Ebasco Constructors Inc.)	2 x 50	2 x 349,150	6.0	90	1993	Combined Cycle

Dutchess County RRF Expansion Poughkeepsie, NY (Westinghouse Electric / RESD)	15	+ 49,660	5.0	79	1993	WTE
Samalayuca II Power Station Comision Federal de Electricidad Samalayuca, Mexico (Bechtel Corporation)	210	1,296,900	7.0	99	1993	Combined Cycle
Potter Station Potter Station Power Limited Potter, Ontario (Monenco/Bluebird)	20	181,880	3.8	66	1993	Combined Cycle
Streeter Generating Station Municipal Electric Utility City of Cedar Falls, Iowa Cedar Falls, Iowa (Stanley Consultants)	40	246,000	3.5	50	1993	PAC Systemä (Turnkey)
MacArthur Resource Rec. Facility Islip Resource Recovery Agency Ronkonkoma, New York (Montenay Islip Inc.)	11	40,000	4.8	79	1993	WTE (Turnkey)
North Bay Plant Transcanada Pipelines North Bay, Ontario, Canada	30	245,000	2.0	53.6	1994	Combined Cycle
Kapuskasing Plant Transcanada Pipelines Kapuskasing, Ontario, Canada	30	245,000	2.0	53.6	1994	Combined Cycle
Haverhill RRF Expansion Ogden Martin Sys. of Haverhill Haverhill, MA	46.9	+44,500	5.0	85	1994	WTE
Arbor Hills Landfill Gas Facility Browning-Ferris Gas Services Inc. Northville, MI (European Gas Turbines Inc.)	9	87,390	3.0	50	1994	Combined Cycle
Pine Bend Landfill Gas Facility Browning-Ferris Gas Services Inc. Eden Prairie, MN (European Gas Turbines Inc.)	6	58,260	3.0	50	1994	Combined Cycle

Pine Creek Power Station **Energy Developments Ltd.** Pine Creek, Northern Territory, Australia (Davy John Brown Pty. Ltd.)	10	95,300	3.63	77	1994	Combined Cycle
Cabo Negro Plant **Methanex Chile Limited** Punta Arenas, Chile (John Brown)	6	74,540	4.0	63	1995	Methanol Plant
Esmeraldas Refinery **Petro Industrial** Esmeraldas, Ecuador (Tecnicas Reunidas, S. A.)	15	123,215	4.5	87.3	1995	Combined Cycle
Mallard Lake Landfill Gas Facility **Browning-Ferris Gas Services Inc.** Hanover Park, IL (Bibb & Associates Inc.)	9	101,400	3.0	49	1996	Combined Cycle
Riyadh Power Plant #9 **SCECO** Riyadh, Saudi Arabia (Raytheon Engrs. & Const., Inc.)	4 x 107	4 x 966,750	16.5	122	1996	Combined Cycle (1200 MW Total)
Barry CHP Project **AES Electric Ltd.** Barry, South Wales, UK (TBV Power Ltd.)	100	596,900	3.0	50	1996	Combined Cycle
Zorlu Enerji Project **KORTEKS** Bursa, Turkey (Stewart & Stevenson International)	10	83,775	3.5	59	1997	Combined Cycle
Tucuman Power Station **Pluspetrol Energy, S.A.** El Bracho, Tucuman, Argentina (Black & Veatch International)	150	1,150,000	5.0	99	1997	PAC Systemã
Grumman **TBG Cogen** Bethpage, NY (General Electric)	13	105,700	5.4	59	1997	PAC Systemã

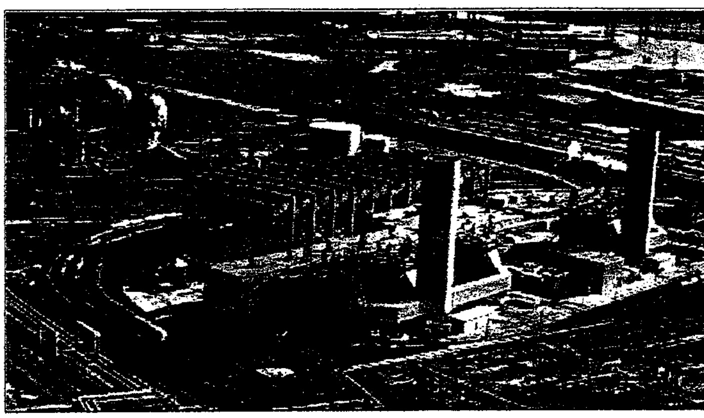
Dighton Power Project **Dighton Power Associates, Ltd.** Dighton , MA (Parsons Power Group, Inc.)	60	442,141	5.5	90	1997	Combined Cycle
El Dorado **El Dorado LLC** Boulder, NV (Sargent & Lundy)	150	1,065,429	2.5	67	1998	Combined Cycle
Tiverton Power Project **Tiverton Power Associates, Ltd.** Tiverton, RI (Stone & Webster Engineering Corp.)	80	549,999	5.0	90	1998	Combined Cycle
Coryton Energy Project **Intergen** Corringham, England (Bechtel Power Corp.)	250	1,637,312	2.0	50	1998	Combined Cycle
Rumford Power Project **Rumford Power Associates, Ltd.** Rumford, ME (Stone & Webster)	80	545,800	5.0	90	1998	Combined Cycle
Keelung RRRP **EPA, R.O.C.** Keelung City, Taiwan (Dahin Co., Ltd.)	25	161,185	5.3	89.6	1999	WTE
Lih-Tser RRRP **EPA, R.O.C.** Yi Lan County, Taiwan (Dahin Co., Ltd.)	25	154,235	5.3	82.4	1999	WTE

NOTE:	(1) Steam side of cycle only
NOTE:	Additional references can be provided, upon request. GEA has supplied approximately 500 Air Cooled Condensers worldwide.

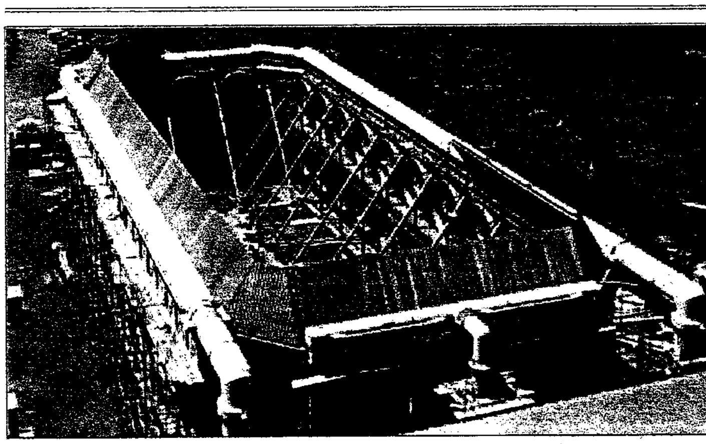
GEA Power Cooling Systems, Inc.

Air Cooled Condenser Installation Photos

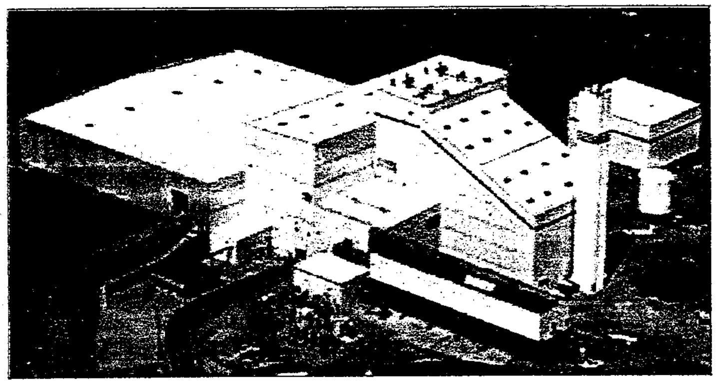
HOMEPAGE



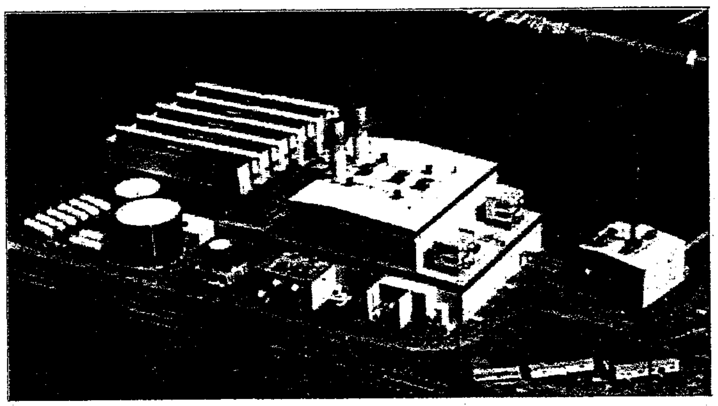
Station:	Linden Cogeneration Plant
Owner:	Cogen Technologies, Inc.
Purchaser:	Ebasco
Year of Installation:	1990
Generation:	285 MW*
Steam Flow:	1,911,000 lb/hr
Ambient Air Temperature:	12° C (54° F)
Back Pressure:	2.44 in. HgA



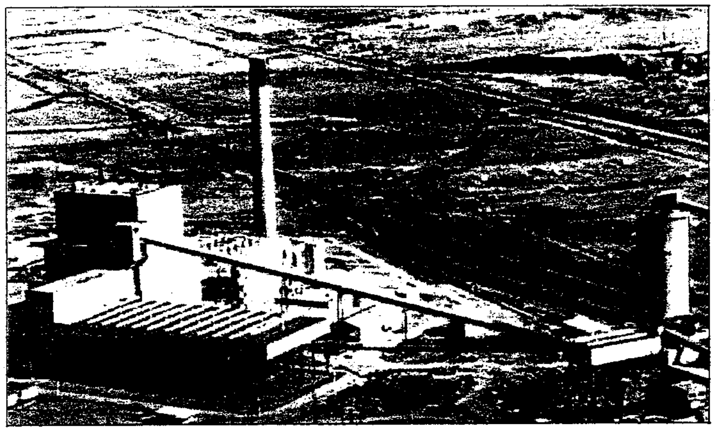
Station:	Maalaea Unit #15
Owner:	Maui Electric Company
Purchaser:	Stone & Webster
Year of Installation:	1992
Generation:	20 MW*
Steam Flow:	158,250 lb/hr
Ambient Air Temperature:	35° C (95° F)
Back Pressure:	6.0 in. HgA



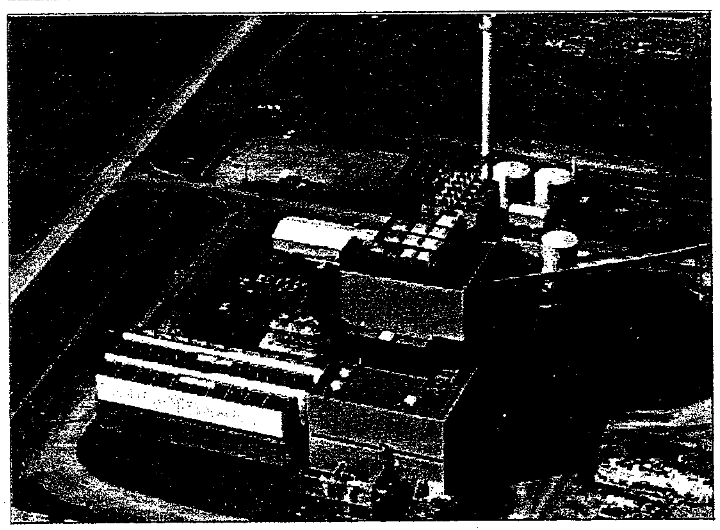
Station:	Spokane Waste-to-Energy Facility
Owner:	Wheelabrator Environmental Systems
Purchaser:	Clark-Kenith
Year of Installation:	1990
Generation:	26 MW
Steam Flow:	153,950 lb/hr
Ambient Air Temperature:	8° C (47° F)
Back Pressure:	2.0 in. HgA



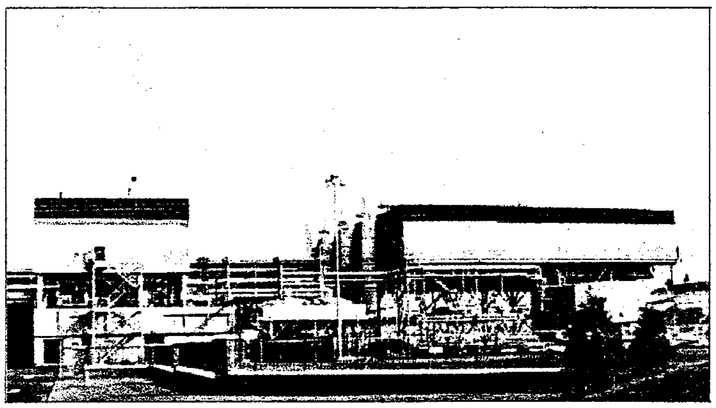
Station:	Saranac Energy Plant
Owner:	Calpine
Purchaser:	Zurn/Nepco
Year of Installation:	1993
Generation:	80 MW*
Steam Flow:	736,800 lb/hr
Ambient Air Temperature:	32° C (90° F)
Back Pressure:	5.0 in. HgA



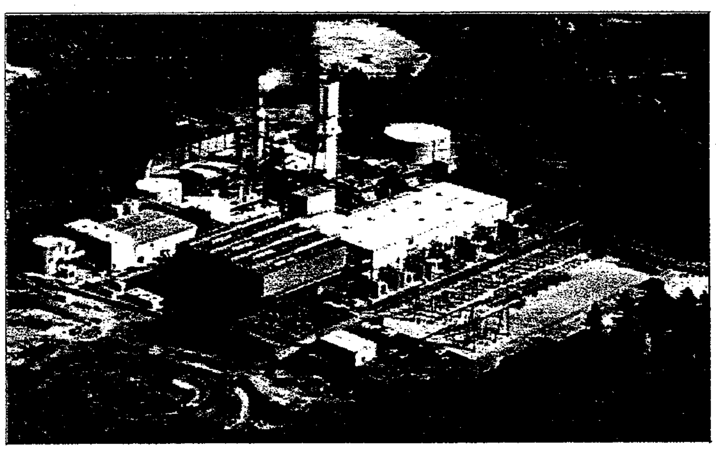
Station:	365 MW Wyodak Power Station
Owner:	Black Hills Power & Light Co./Pacific Power & Light
Purchaser:	Stone & Webster
Year of Installation:	1978
Generation:	330 MW (steam cycle)
Steam Flow:	1,884,806 lb/hr
Ambient Air Temperature:	19° C (66° F)
Back Pressure:	6.0 in. HgA



Station:	Neil Simpson II Station
Owner:	Black Hills Power & Light
Purchaser:	Black & Veatch
Year of Installation:	1994
Generation:	80 MW
Steam Flow:	548,280 lb/hr
Ambient Air Temperature:	19° C (66° F)
Back Pressure:	6.0 in. HgA



Station:	Sayreville Cogeneration
Owner:	Plant
Purchaser:	Intercontinental Energy Co.
Year of Installation:	Westinghouse Electric Corp.
Generation:	1989
Steam Flow:	90 MW*
Ambient Air	714,900 lb/hr
Temperature:	15° C (59° F)
Back Pressure:	3.0 in. HgA



Station:	Bellingham Cogeneration Plant
Owner:	Intercontinental Energy Co.
Purchaser:	Westinghouse Electric Corp.
Year of Installation:	1989
Generation:	90 MW*
Steam Flow:	714,900 lb/hr
Ambient Air Temperature:	15° C (59° F)
Back Pressure:	3.0 in. HgA

* *Steam cycle only.*

EXHIBIT I - 6

ORIGINAL

STATUS OF POWER PLANT PROJECTS: Sept.01

Project Name	Location	Status	Size Mw	Nox NH_3 CO Limits (gas)	Cooling Method	Fuel
Berkshire	Agawam	Start-up	272	3.5 ppm 10 ppm 4 ppm	Wet	Gas and Oil Combined cycle
Dighton	Dighton	Start-Up	170	3.5 ppm 10 ppm 6 ppm	Dry	Gas Combined cycle
Millennium	Charlton	Start-Up	360	3.5 ppm 10 ppm 4 ppm	Wet -Fresh	Gas and Oil Combined cycle
ANP Blackstone	Blackstone	Fired-Up	580	2 ppm 2 ppm 3 ppm	Dry	Gas Combined cycle
ANP Bellingham	Bellingham	Final Permit Issued 7/99	580	2 ppm 2 ppm 3 ppm	Dry	Gas Combined cycle
Sithe Mystic	Everett	Final Approval issued 1/25/00	1500	2 ppm 2 ppm 2 ppm	Dry	Gas Combined cycle
Cabot Island End	Everett	Final Approval Issued 2/00 permit expires soon	350	2 ppm 2 ppm 2 ppm	Dry	Gas Combined Cycle
Sithe Fore River	Weymouth	Final Approval Issued 5/5/00	750	2 ppm 2 ppm 2 ppm	Dry	Gas and Oil Combined cycle
Medway Station	Medway	Conditional Approval 12/1/2000	540	9 ppm N/A 9 ppm	Dry	Gas Simple cycle
IDC Bellingham	Bellingham	Draft conditional approval	525	1.5 ppm 2.0 ppm 2.0 ppm	Dry	Gas Combined cycle
Con Ed Springfield	W. Springfield	Construction	93	2 ppm 2 ppm 5 ppm	Wet-Fresh	Gas Simple cycle
UAE	Lowell	Proposed conditional 4/24/2001	96	2 ppm 2 ppm 5 ppm	Wet	Gas Simple cycle
Kendall Sq. Upgrade	Cambridge	Conditional Approval	234	2 ppm 2 ppm	Wet-Fresh	Gas & oil Combined

		9/12//01		2 ppm		cycle
Nickel Hill	Dracut	On hold Due Diligence	750	To Be Determined	Wet Fresh	Gas Combined cycle
Canal 2	Sandwich	Permit App. Submitted	1,225	To Be Determined	Wet-Marine	Gas and Oil Combined cycle
Brockton Power	Brockton	Inactive	270	To Be Determined	Wet-WWTP Effluent	Gas and Oil
ESI New Bedford	New Bedford	Dead	270	To Be Determined	Wet-Fresh	Gas and Oil

EXHIBIT I - 7

ORIGINAL

AIR-COOLED HEAT EXCHANGERS

AND

COOLING TOWERS

Thermal-flow performance evaluation and design

Detlev G Kröger

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1998

The cover: Temperature distribution in the plume above an air-cooled heat exchanger. With permission from dr. W.A.Schreüder.

1.2 AIR-COOLED HEAT EXCHANGERS

In an air-cooled heat exchanger, or air cooler, heat is usually transferred from the process fluid to the cooling air stream via extended surfaces or finned tubes. While the performance of wet-cooling systems is primarily dependent on the ambient wetbulb temperature, the performance of air-cooled heat exchangers is determined by the drybulb temperature of the air which is usually higher than the wetbulb temperature and experiences more dramatic daily and seasonal changes.

Small air-cooled heat exchangers (compact heat exchangers [84KA1]) find application in many areas including computers and other electronic equipment, vehicles (radiators, oil coolers, intercoolers [75US1]), air-conditioning and refrigeration plants (condensers [88PL1, 94MC1]), etc. Larger air-cooled heat exchangers are found in refrigeration and chemical plants, various process industries and power plants. Movement of the cooling air is achieved by mechanical means (fans) or buoyancy effects (e.g. natural draft dry-cooling tower).

Although the capital cost of an industrial air-cooled heat exchanger is usually higher than that of a water-cooled alternative (this need not always be the case) the cost of providing suitable cooling water and other running expenses may be such that the former is more cost effective over the projected life of the system. Other considerations are also of importance depending on the process or application [74MA1]. In arid areas where insufficient or no cooling water is available, air cooling is the only effective method of heat rejection.

1.2.1 MECHANICAL DRAFT

Various air-cooled heat exchanger configurations are found in practice. In some situations the choice of design is however critical to the proper operation of the plant. Air-cooled heat exchangers may be of the forced or induced draft type. In the case of the former the fans are installed in the cooler inlet air stream below the finned tube heat exchanger bundle as shown for a particular example in figure 1.2.1, with the result that the power consumption for a given air mass flow rate is less than that for the induced draft configuration. The fan drives located in the cooler air flow below the unit are also easier

I-8 ORIGINAL

WATER SUPPLY ISSUES WORKSHOP SUMMARY

INTRODUCTION

On February 8, 2001 the Siting and Environmental Protection Committee of the California Energy Commission (Energy Commission) conducted a workshop on water issues that may constrain the licensing of future power plants in California and to discuss strategies to address these issues. The three topics discussed at the workshop included: (1) water supply and water regulations, (2) technological solutions, and (3) water policy issues.

OVERVIEW OF ORAL PRESENTATIONS

OVERVIEW OF WATER SUPPLY ISSUES

Mr. Joe O'Hagan, representing the Energy Commission staff, provided a brief overview of water issues addressed in siting cases. Although on a statewide basis power plants are not major consumers of water as compared to agricultural and urban uses, powerplant consumption of water on a local level is often large compared to other uses. Therefore, water supply issues are often of concern to the public.

Mr. O'Hagan stated that most proposals for power plant water supply have been workable. However, a lack of information about project impacts on water supply in the early stages of the staff assessment process has often led to delays in completing the siting process.

PANEL 1: WATER SUPPLY AND WATER REGULATIONS

Mr. Ed Anton, Acting Executive Director SWRCB

Mr. Ed Anton stated that the State Water Resources Control Board (SWRCB or State Board) and Regional Water Quality Control Boards (Regional Boards) regulate two aspects of water within California. The first is water supply that is regulated by the State Water Resources Control Board-primarily for power plants through the Policy on Inland Sources of Cooling Water. Water quality is regulated primarily through the Regional Boards through the issuance of discharge permits.

Mr. Anton explained that the State Water Resources Control Board's Policy on Inland Sources of Cooling Water (Order 75-58) sets up a priority of water sources that should be used for cooling, such as wastewater that would otherwise be discharged to the ocean. This policy, however, consistent with the Energy Commission approach to the policy is that it "...was not set up as an absolute...(page 6, lines 22-23)." The policy does call for the consideration of alternative cooling water sources. Also addressed by the policy is the discharge of wastewater. Since the use of evaporative cooling in a power plant concentrates the salts, the policy calls for wastewater to be discharged to salt sinks or lined ponds.

These questions whether not addressed in great detail during the workshops. Many of the panel members supported staff's approach to evaluating local water issues, and its evaluation of alternative cooling technologies and water sources. Still other panel members advocated a more rigorous consideration of the water policy issue raised by the use of fresh inland water for powerplant cooling.

STAFF RECOMMENDATIONS BASED ON WORKSHOP DISCUSSIONS

The supply of water in California is critical for development in every sector of the economy. Although there are a number of sources from which water supply can be expanded, ultimately there is a limited supply of water in California. It is in the states interest to estimate the need for water in the state from all sectors and to evaluate options for expanding the supply of water, and to evaluate alternatives to the use of fresh inland water, including ground water. Staff recommends that the Energy Commission consider the following to ensure that an adequate supply of water is available for powerplant cooling in the state.

A. The Energy Commission staff should provide DWR with estimates of the existing and future needs for water for powerplant cooling, to facilitate DWR's water resource planning efforts.

B. The Energy Commission staff should work with DWR and the State Water Resources Control Board (SWRCB) to identify potential sources of water for powerplant cooling. These sources should include wastewater and fresh water (including ground water). Staff, DWR and SWRCB should also identify areas in the state where powerplant development using fresh water should be discouraged, due to critical under supply of fresh water or due to expected future growth in other sectors of the economy.

C. The Energy Commission staff should work with the Coastal Commission, Regional Water Quality Control Boards and State Water Resources Control Board to identify potential future locations for coastal repowering powerplant development, to identify issues that must be addressed before approving that development, and to identify the information that powerplant developers will need to obtain to expedite licensing of these repowering powerplants.

D. Staff recommends that the Energy Commission develop and implement a policy that requires new generation to maximize water conservation measures for power plant cooling. SWRCB Resolution 75-58 requires the evaluation of alternative water supplies and/or cooling technologies. This policy, however, merely mandates the consideration of alternatives and does not prohibit the use of freshwater for cooling, even if such alternatives are readily available. Therefore, staff believes that this policy does not adequately address the true costs of using fresh or even potable water for power plant cooling in California. In light of California's looming water supply crisis, the use of fresh or even potable water for power plant cooling poses issues that are ignored by the economic or California Environmental Quality Act (CEQA) criteria used by staff in past siting cases to determine the suitability of using alternative sources of cooling water or alternative cooling technology. For example, due to the greater capital cost and efficiency penalty associated with dry cooling, the reliance on economic criteria will almost always favor wet cooling and ignores long term reliability concerns as well as issues of protection of a limited resources.

The greatest emphasis in such a policy should be given to the use of dry cooling because, although more expensive, dry cooling significantly reduces facilities' water demand, removes a major siting constraint and ensures facility reliability during emergencies and droughts.

Emphasis should also be on using alternative sources of cooling water-such as wastewater, brackish groundwater, etc. These sources provide many of the same benefits of using dry cooling, although information requirements to properly evaluate such alternatives may delay the siting process. Finally, the policy should require whenever the use of fresh water is unavoidable, the maximum utilization of this resource. Projects using freshwater should be required to cycle this water 20 times or more and utilize zero discharge. This way the maximum use of the resource is achieved without raising water quality issues from wastewater discharge.

EXHIBIT I - 17

ORIGINAL

CUMULATIVE IMPACTS OF AGRICULTURE EVAPORATION BASINS ON WILDLIFE

Technical Report

Prepared for

DEPARTMENT OF WATER RESOURCES

Submitted by

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and

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February 1993

Chapter 5

CUMULATIVE EFFECTS OF EVAPORATION BASINS ON WILDLIFE

CEQA defines cumulative impacts in the following way: "Cumulative impacts" refers to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts.

(a) The individual effects may be changes resulting from a single project or a number of separate projects.

(b) The cumulative impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time.

Two factors may alter the number or area of evaporation basins in the southern San Joaquin Valley. These are the possible addition of up to 1,990 acres of new or enlarged evaporation basins bringing the total to approximately 9,000 acres, and the anticipated closure of Basin Nos. 4, 7, 18, and 20, which would reduce the total evaporation basin acreage by 220 acres.

The magnitude of adverse effects of evaporation basins may also change as pond operators implement interim and long-term management programs. Evaporation basin operators have entered into interim management agreements with DFG, which are described in more detail in Chapter 6 of this report. Most of these agreements were signed in 1990, so the effects of interim management are not reflected in the data collected. The management methods used are expected to decrease the number of birds exposed to basins with selenium levels of concern, therefore, the magnitude of effects specifically related to the exposure of birds should also decrease. Pond operators, in preparing site-specific reports and making independent efforts to minimize exposure, will further lessen the adverse effects.

The discussion of cumulative effects which follows is organized similarly to the earlier chapters (e.g., bird reproduction, bird health, migrating and wintering birds). While data are sometimes sparse, we have attempted to categorize cumulative effects as adverse, beneficial, or unknown. These categorizations are difficult because many potential effects are not well studied and are subject to considerable debate. Such points of controversy have been described throughout this report.

This report is not intended to be a thorough evaluation of individual site-specific effects, but rather is intended to provide an overview of the situation, and to portray potential cumulative impacts. Chapter 4 of this report discussed the kinds of impacts which could occur at individual basins. Primary potential adverse effects of primary concern include effects to bird reproduction and bird health. The foremost task of this chapter is to determine if these effects may have cumulative impacts as defined above. This chapter, in particular, is intended to review the potential impacts of the combined individual ponds in light of regional breeding populations and visitant birds and other wildlife. This comparison is important for making an informed decision about the significance of potential cumulative effects.

In simplest terms, if only a few birds are at risk, and they represent only a tiny fraction of the total number of birds in the area, then cumulative impacts might not be significant. Conversely, if a considerable number of birds are at risk, and they represent a significant portion of the birds in the area, then cumulative effects are likely to be significant (even though impacts at individual ponds might be less than significant).

RISK CHARACTERIZATION

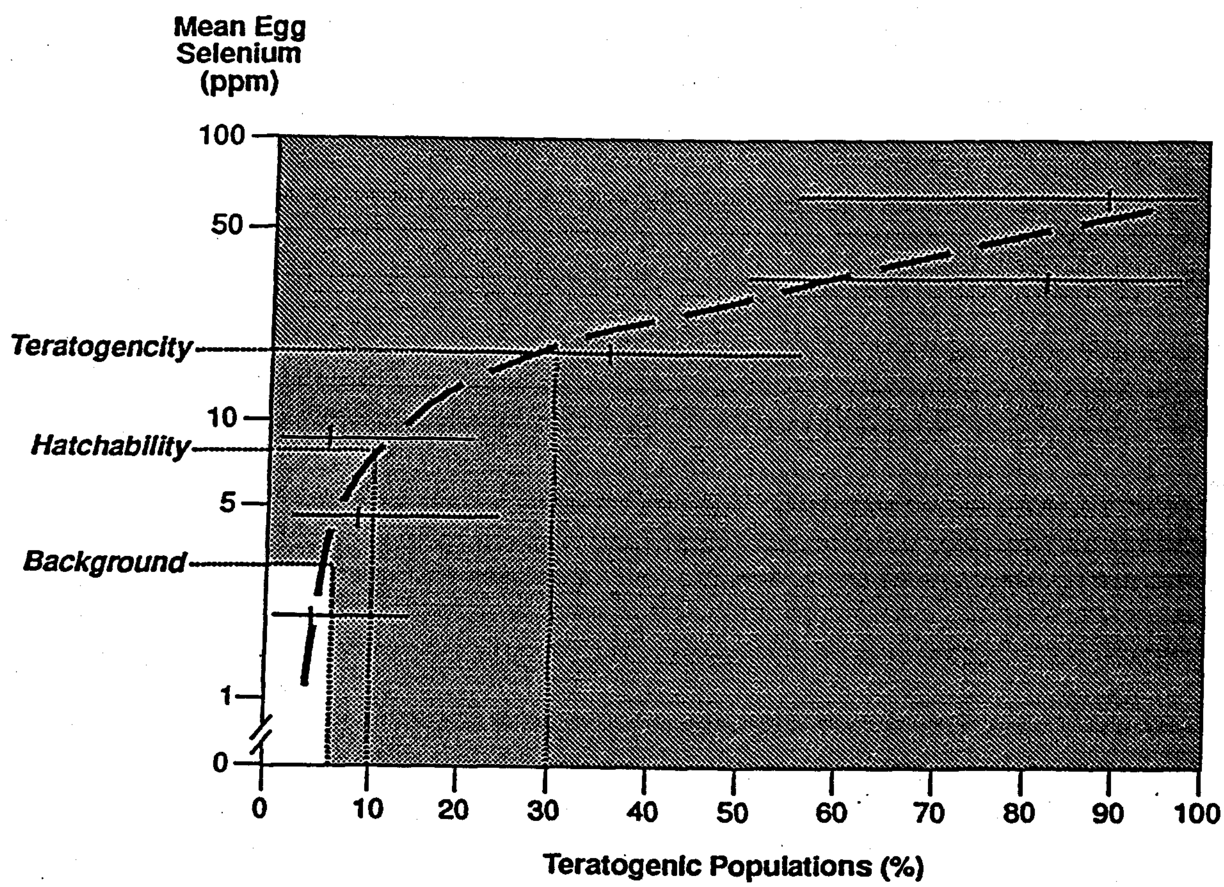
The primary task of risk characterization should be completed in the site-specific reports. Nonetheless, an initial attempt was made in this report to determine rough proportions of locations which pose risks due to elevated selenium levels.

It is clear from earlier chapters (especially Chapter 4) that birds occur at the evaporation basins, sometimes in large numbers. It is also clear that reconnaissance-level sampling of a portion of the sites for selenium bioaccumulation showed that such accumulation was indeed occurring. Reproductive effects, including nest failures and teratogenesis, occurred at some of the sampled ponds.

An objective of this report is to help decision-makers make informed judgements through extrapolation of available data. To achieve this objective, data concerning methods of predicting whether breeding birds at evaporation basins might show reproductive effects were reviewed, and the most accurate data presented in this report. Since site-specific data were often lacking, a method of predicting the possibility of a population exhibiting reproductive effects based on available data was needed. In some cases, selenium concentrations in eggs, invertebrates, and water were all available, and nest surveys had been completed. In other cases, only partial data were available (e.g. water concentrations from a single cell of a multi-cell site.)

A series of nearly 200 published and unpublished sample means were reviewed to help define potential relationships between selenium concentrations in water, invertebrates, and waterbird eggs and to relate those concentrations to waterbird populations which showed reproductive effects associated with the selenium.

Selenium concentrations in eggs of birds nesting at uncontaminated reference sites throughout the United States average less than 3 ppm dry weight (Figure 5-1; and Skorupa



Selenium concentration thresholds are shown as background (<3 ppm), hatchability effects expected (8 ppm), and teratogenicity expected (18.5 ppm. the mid-point of the range where such effects have been observed).

Figure 5-1
Relationship Between Average Egg Selenium Concentration in Bird Eggs and Probability of Observing Teratogenicity Among the Sampled Populations

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and Ohlendorf, 1991). These background concentrations of selenium in eggs were used to establish baseline rates of egg hatchability and teratogenesis in the unaffected populations. The threshold for mean egg selenium associated with increased hatchability effects was 8 ppm. Such hatchability effects were statistically significant at egg selenium levels above 8 ppm, but no teratogenic effects were evident. In the Tulare Basin, average egg selenium concentrations of 8 ppm or more in avocets and stilts were associated with impaired hatchability in these populations.

The threshold for mean egg selenium associated with increased teratogenic effects in bird populations was found to be in the range of 13 to 24 ppm. The midpoint of this range (18.5 ppm) was used in further estimates.

A decision was made to first develop a relatively conservative model (one which likely underestimated effects) for initial analysis. If potential cumulative effects were predicted to be significant by this conservative model, then mitigation would be warranted.

In order to develop this model, we decided to combine data from populations with egg selenium in the range from 3-8 ppm (unknown effects from Chapter 4) with those sites with approximately background levels (less than 3 ppm). Hatchability effects were predicted at greater than 8.0 ppm. Then we chose a mid-point (18.5 ppm) in the range (13-24 ppm) of selenium levels at which populations might show teratogenic effects.

Finally, we prepared estimates of the dietary and waterborne selenium concentrations which could produce egg selenium levels at these threshold levels (Table 5-1). Again, we were conservative in our estimates, using the upper confidence level of the value as our predictor. The upper value of each confidence interval estimate represents the highest average dietary or waterborne concentration that would be expected to produce the selected mean egg selenium threshold concentration. The maximum likelihood estimates (MLE) represent the best estimates (based on regression lines) for those average dietary and waterborne threshold concentrations. Note that discussion in Chapter 4 referred to these dietary MLE numbers (2.9 and 5.9 ppm) as being thresholds for hatchability and teratogenic effects.

Table 5-1
Selenium Risk Characterization for Waterbirds

	Risk Thresholds		
	Background	**Hatchability**	**Terato-genesis**
Mean Egg Selenium (ppm, dry weight; population mean)	<3.0	>8.0	>18.5[d]
Dietary Selenium (ppm, dry weight)			
MLE[a]	<1.2	>2.9	>5.9
95% CI[b]	(0.8)[c] - 1.7	2.2 - 3.5	4.8 - 7.4
Waterborne Selenium (ppb, total recoverable)			
MLE	<(0.5)	>2.7	>12
90% CI	(0.04) - 2.3	(0.5) - 7.8	3.5 - 32

[a]MLE = Maximum Likelihood Estimate - based on regression lines.
[b]CI = Confidence Interval - based on upper and lower confidence boundaries of regression equations. Note that dietary selenium is a 95% CI because it is based on a single regression equation, but waterborne selenium is a 90% CI because it is based on estimation using two regression equations.
[c]Estimates shown in parentheses are based on extrapolations because data are not available for lower portions of the range.
[d]Range = 13 - 24
Source: Skorupa and Ohlendorf, 1991; Skorupa, unpubl. data.

The relationships between selenium concentrations in birds' eggs, their diets, and waterborne selenium in evaporation basins are illustrated in Figures 5-2 through 5-4. The regression lines in these figures reflect the process of bioaccumulation of selenium in the food chain.

In each of these figures, we illustrate (in a counter-clockwise direction) the relationships between (1) selenium concentrations found in aquatic invertebrates and water from evaporation basins (J. Shelton et al., DWR, unpubl. data), (2) average selenium concentrations found in mallard eggs when the ducks were fed various concentrations of dietary selenium (Heinz et al., 1989), and (3) the frequency of bird populations with detectable embryo abnormalities (teratogenesis) as a function of mean egg selenium concentrations (Skorupa and Ohlendorf, 1991). The dashed line (or "box") in the center of each figure connects selected mean egg selenium concentrations to the maximum dietary and waterborne selenium concentrations that are expected to produce those mean egg selenium concentrations. (The dashed lines intercept the lower 95 percent confidence intervals for those two regression equations.)

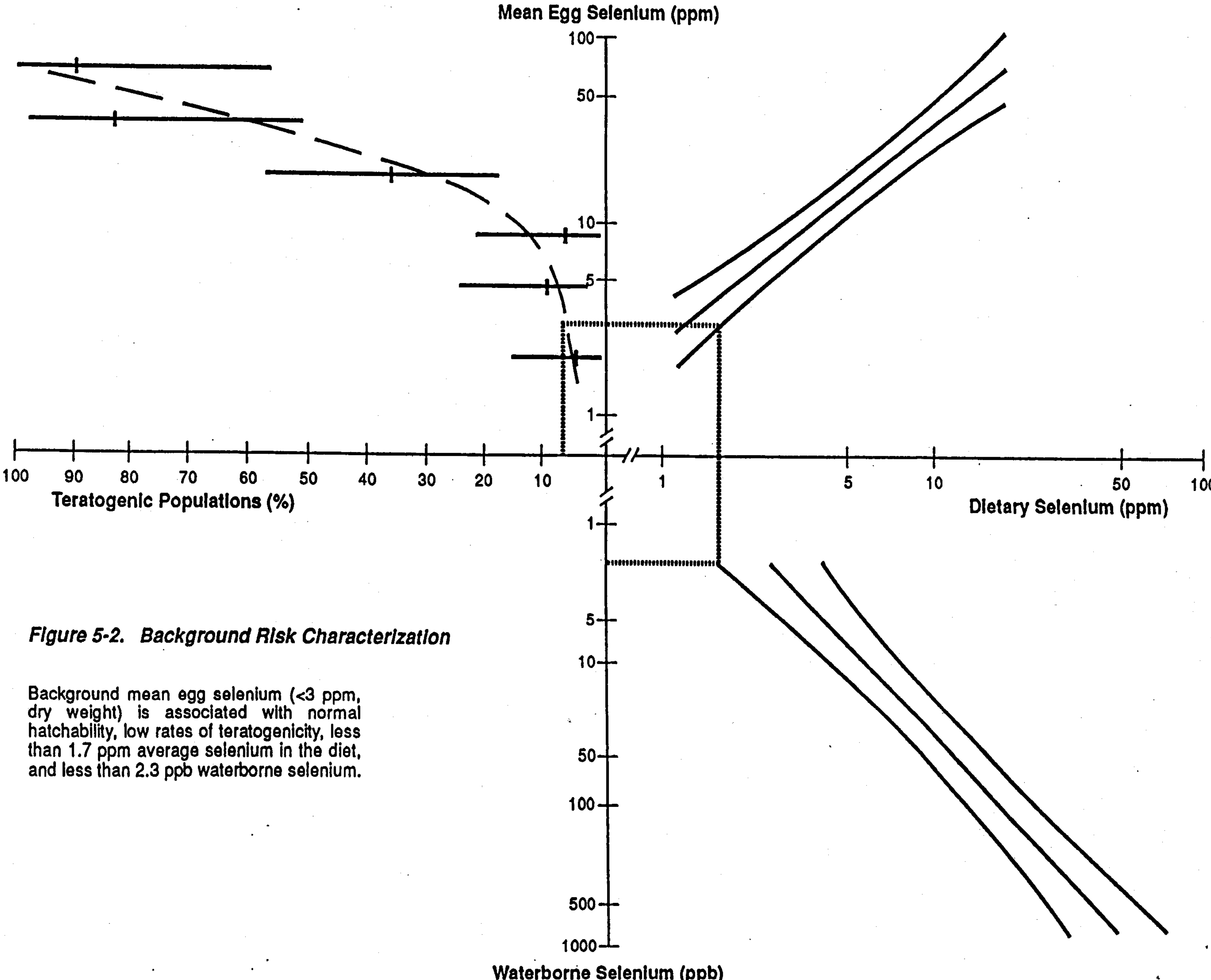

Figure 5-2. ***Background Risk Characterization***

Background mean egg selenium (<3 ppm, dry weight) is associated with normal hatchability, low rates of teratogenicity, less than 1.7 ppm average selenium in the diet, and less than 2.3 ppb waterborne selenium.

Source: Modified from Skorupa and Ohlendorf (1991).

Figure 5-2

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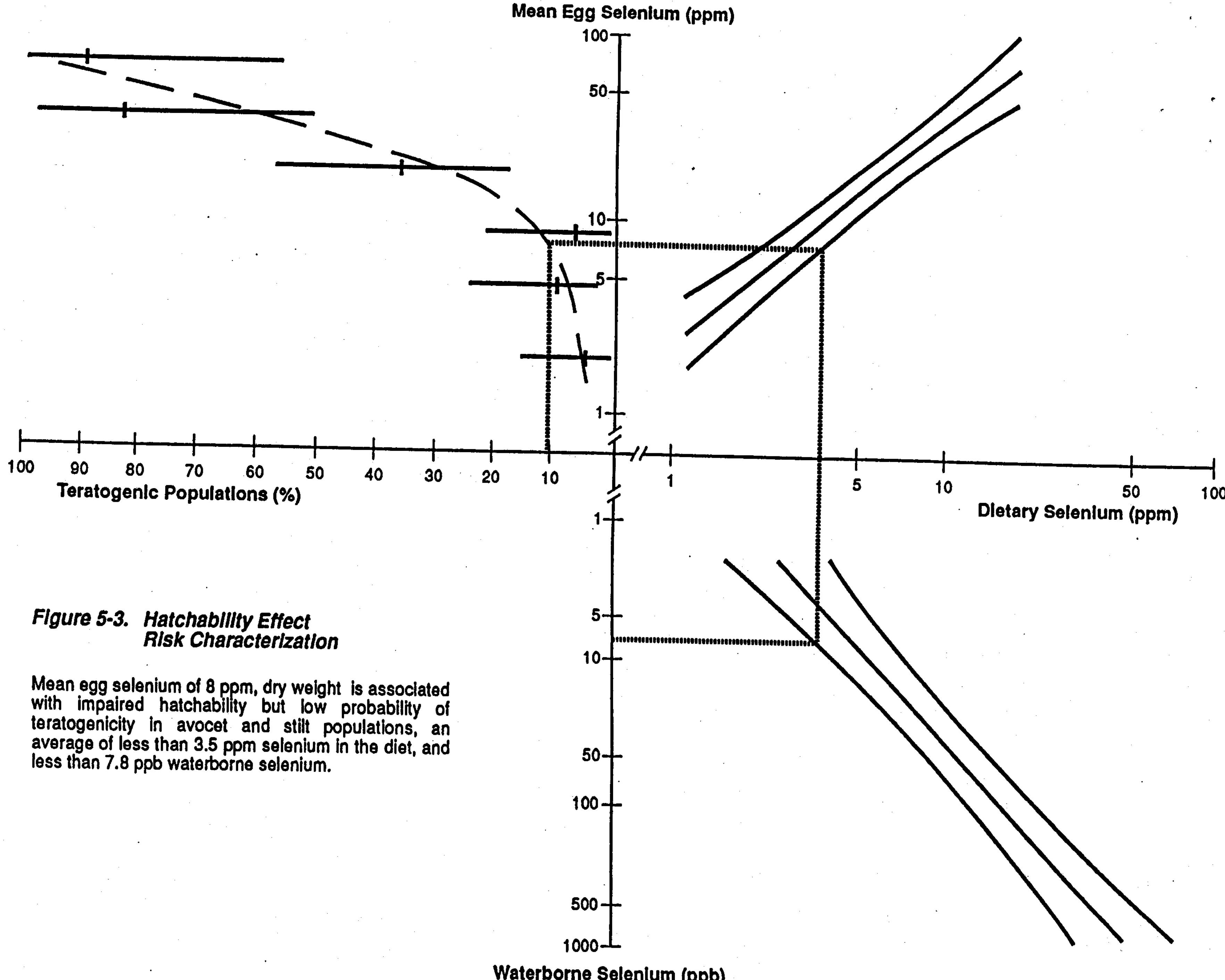

Figure 5-3. ***Hatchability Effect Risk Characterization***

Mean egg selenium of 8 ppm, dry weight is associated with impaired hatchability but low probability of teratogenicity in avocet and stilt populations, an average of less than 3.5 ppm selenium in the diet, and less than 7.8 ppb waterborne selenium.

Source: Modified from Skorupa and Ohlendorf (1991).

Figure 5-3 CH2M HILL

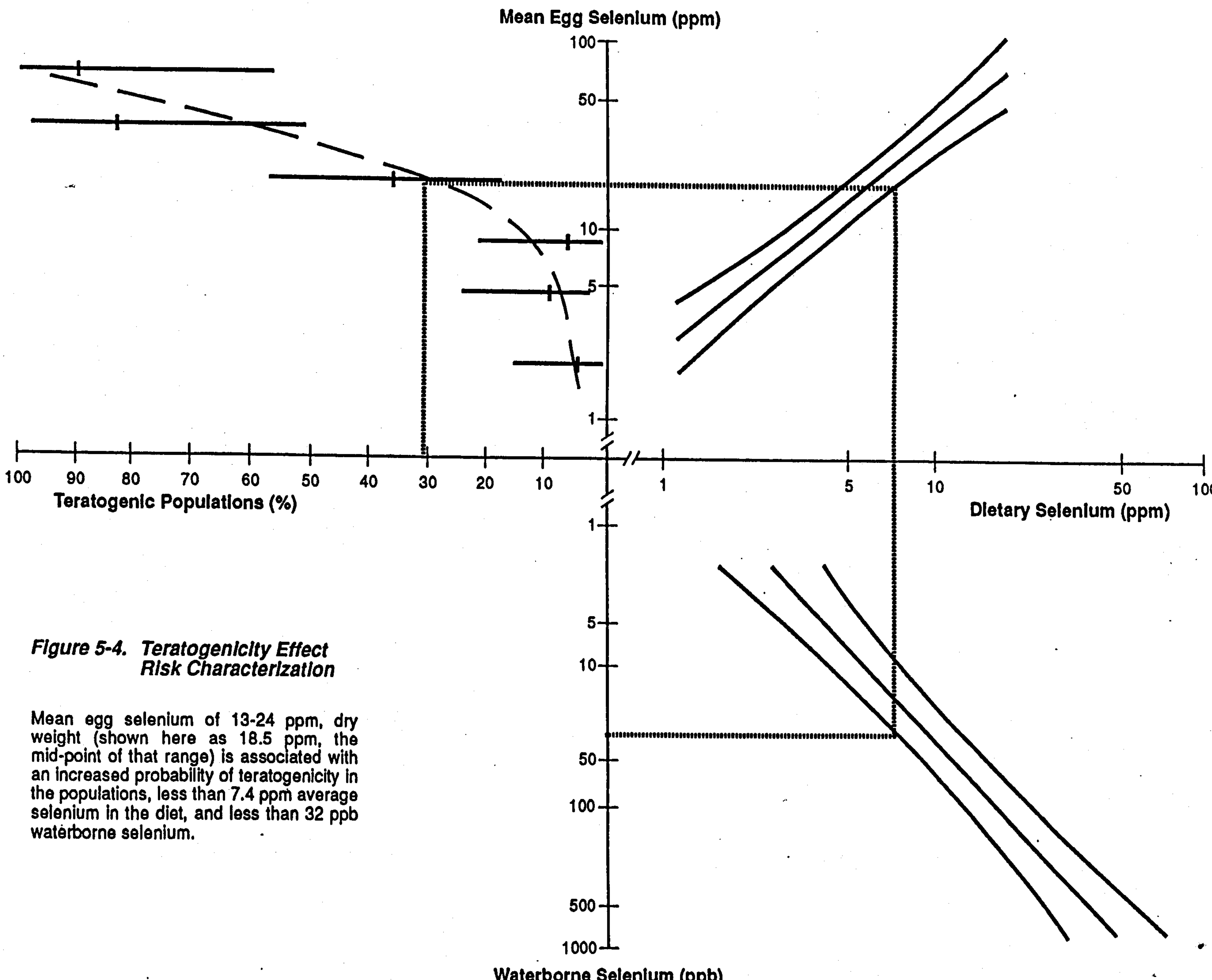

Figure 5-4. Teratogenicity Effect Risk Characterization

Mean egg selenium of 13-24 ppm, dry weight (shown here as 18.5 ppm, the mid-point of that range) is associated with an increased probability of teratogenicity in the populations, less than 7.4 ppm average selenium in the diet, and less than 32 ppb waterborne selenium.

Source: Modified from Skorupa and Ohlendorf (1991).

Figure 5-4 CH2M HILL

The upper left quadrant of each figure shows the relationship between mean egg selenium and teratogenicity in aquatic bird populations expressed as the probability of detecting teratogenesis in a reconnaissance-level sample of embryos. In that portion of the figure, each small vertical bar is the observed percentage of the populations, within certain ranges of mean egg selenium, in which embryo deformities were detected. The horizontal line shows the 95 percent confidence interval for this value. The number of individuals being affected in those populations showing evidence of teratogenicity is usually not known.

These threshold limits (egg, invertebrate, or waterborne selenium) were then used to categorize the evaporation basins based on the likelihood of adverse reproductive effects (hatchability or teratogenicity). A conservative approach was used to initially categorize the basins. The most accurate predictor of effects of selenium on avian reproduction has been selenium content in avian eggs (Skorupa and Ohlendorf 1991). The next most accurate predictors are selenium levels in avian food chains, followed by waterborne concentrations, followed by bird-liver concentrations. Thus, the initial attempt at categorizing the ponds based on potential avian impacts involved a hierarchal classification scheme. Data on egg-selenium concentrations were used where available and overrode results of other sampling. When egg data were not available, food-chain concentrations were used for classification. When food-chain concentrations were not available, water-borne selenium concentrations were used, and so forth. Three categories of classification were used: (1) high probability of hatchability and embryo effects (see thresholds in Table 4-1); (2) probability of reduced hatchability (see Table 4-1); and (3) background and slightly elevated levels of selenium (see Table 4-1) were combined into a single category of minimal or no effect. Thus, each pond is preliminarily classified based on available data, and there is significant variance in the amount of data available from the various ponds. The function of this classification scheme is to obtain a preliminary estimate of the total amount of pond acreage that might significantly affect avian populations. Specific effects of each pond will be assessed in detail in the site-specific reports when data gaps will be filled. Using the categories described above, populations with reproductive effects could occur at 13 evaporation basins (Basins 4, 5, 7, 14, 15, 16, 17, 19, 21, 22, 23, 26, 28) totalling 4,130 acres (Figure 5-5). These sites make up approximately 61 percent of the evaporation basin area in the region. Within these listed basins, ten basins (Basins 4, 5, 15, 16, 17, 19, 21, 22, 23 and 26) were categorized as having possible hatchability and teratogenicity effects. Three more were listed as having possible hatchability effects (Basins 7, 14 and 28). It should be noted that this model made a series of assumptions as described earlier, and that site-specific reports will refine the accuracy of the analysis.

ADVERSE CUMULATIVE EFFECTS

BIRD REPRODUCTION

These basins are used by a variety of waterbirds, many of which use the basins for breeding. Estimates were made of the numbers of birds in the vicinity during the spring and summer

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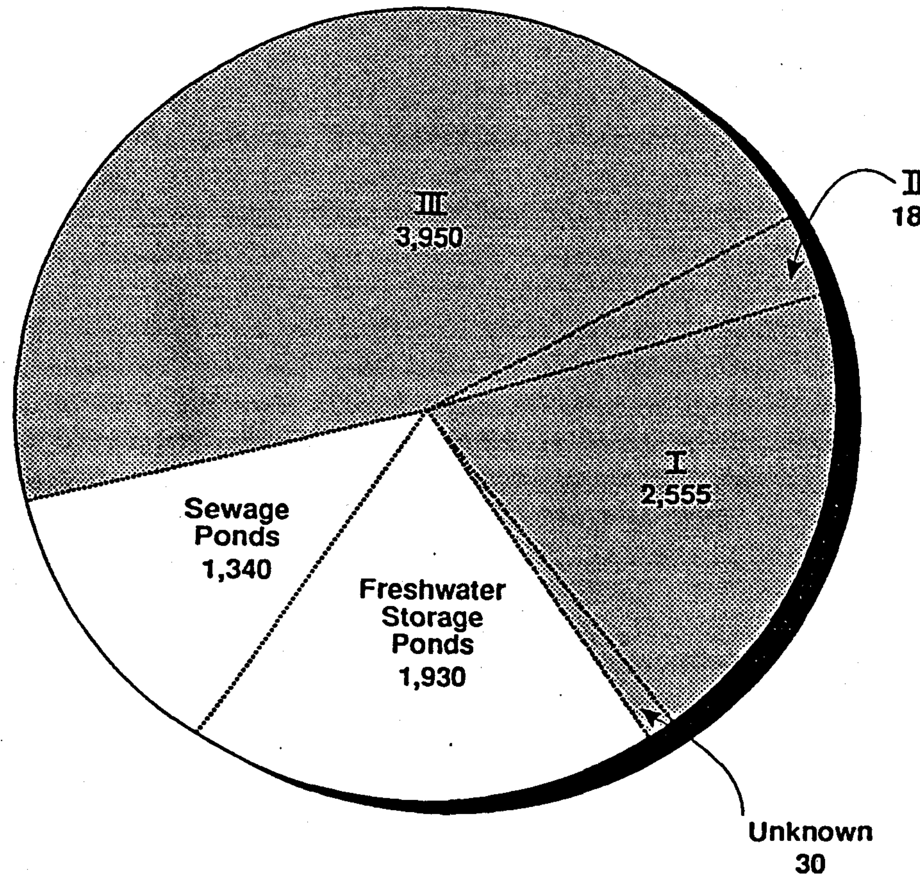

		Acres	
Evaporation Basins		6,715	67.2%
Expected Effects:			
III Hatchability & Teratogenicity	*3,950*	*39.6%*	
II Hatchability	*180*	*1.8%*	
I None	*2,555*	*25.6%*	
Unknown	*30*	*0.3%*	
	6,715	*67.2%*	
Natural Wetlands		0	0%
Sewage Ponds		1,340	13.4%
Freshwater Storage Ponds		1,930	19.3%
		9,985	100%

Figure 5-5
Acres of Wetland Habitat in the Tulare Basin from Spring-Summer (May - July), by Type

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seasons based on three principal sources. These data were provided by USFWS, Sloat and Williams (unpubl. data), and PRBO from their Pacific Flyway Project.

Nesting surveys were conducted at 12 basins during 1987 and/or 1989 by USFWS (Table 4-2). Coverage by these surveys ranged from less than 50 percent to greater than 80 percent of the nesting habitat at the surveyed ponds. Most surveys covered 50 to 75 percent of the basins; thus, the numbers obtained probably underestimate the amount of nesting at those sites. These survey results were presented in Chapters 2 and 4.

The relative species composition of waterbirds nesting at evaporation basins, as derived from USFWS surveys, is 70 percent stilts and avocets, 10 percent terns, 8 percent each ducks and plovers (including killdeer), and 4 percent grebes (Table 2-8) (Skorupa, pers. comm.). The total number of breeding waterbird pairs on all Tulare Basin evaporation ponds was estimated by J. P. Skorupa as 2,315 to 5,951 breeding pairs. These estimates assume that 70 percent to 90 percent of nesting attempts were detected; that nesting attempts per pair averaged 1.2 to 1.6; and that the studied evaporation basins supported 40 percent to 60 percent of the total nesting population on evaporation basins.

Sloat and Williams (unpubl. data) provide results of monthly shorebird counts at 16 evaporation basins, comprising 89 percent (5,950 acres) of the total evaporation basin area. The monthly average spring-summer (May through July) population recorded was 15,908 individuals. These counts included shorebirds as well as other waterbird species. Sixty-seven percent of these individuals were found at basins that had selenium levels at or above the threshold where reproductive effects might be expected to be detected in populations. Some of these basins had known reproductive effects. These surveys detected large numbers of individuals of some species which are not known to breed at the ponds.

Fewer nesting attempts have been recorded for waterfowl than for shorebirds at the evaporation ponds. Waterfowl comprised approximately 8 percent of nesting waterbirds observed (Table 2-7); a maximum of 480 breeding pairs of waterfowl were estimated for all evaporation basins. Additional birds nested nearby and used the ponds for feeding or rearing; but data are not available. Sloat and Williams (unpubl. data) counted an average of 1864 waterfowl at 16 evaporation basins during the spring of 1990. These counts probably included young, other non-breeding members of local populations, and migrants.

Documented nesting attempts were shown in Table 4-2 for 1987 and 1989. Most of the documented waterfowl nesting attempts were from Basin Nos. 11 (TLDD North) and 22 (TLDD South). No reproductive effects were observed at Basin No. 11 in 125 duck nests studied; however, reduced hatchability and increased teratogenesis were observed at Basin No. 22, where 71 duck nests were studied.

Based on USFWS estimates, 4 percent (maximum 240 pairs) of breeding waterbirds at evaporation basins are grebes. Sloat and Williams (unpubl. data) counted an average of 237 grebes per month at 16 evaporation basins (Table 2-1) during the spring of 1990. Reproductive success of this species has been poor on all the basins studied, although this poor reproductive rate has apparently not always been related to selenium levels. The numbers of grebes nesting on evaporation basins showed higher between-year variance than numbers of other bird taxa. Annual counts are expected to vary widely due to a number of factors (Skorupa, pers. comm.).

It is clear that waterbirds of a variety of species are present on the evaporation basins during the breeding season, and that a significant proportion of the breeding population is present at ponds with selenium levels which may reduce the productivity of the population (reduce reproductive success). The potential significance of such a reduction can only be estimated by examining regional populations and habitats available for breeding.

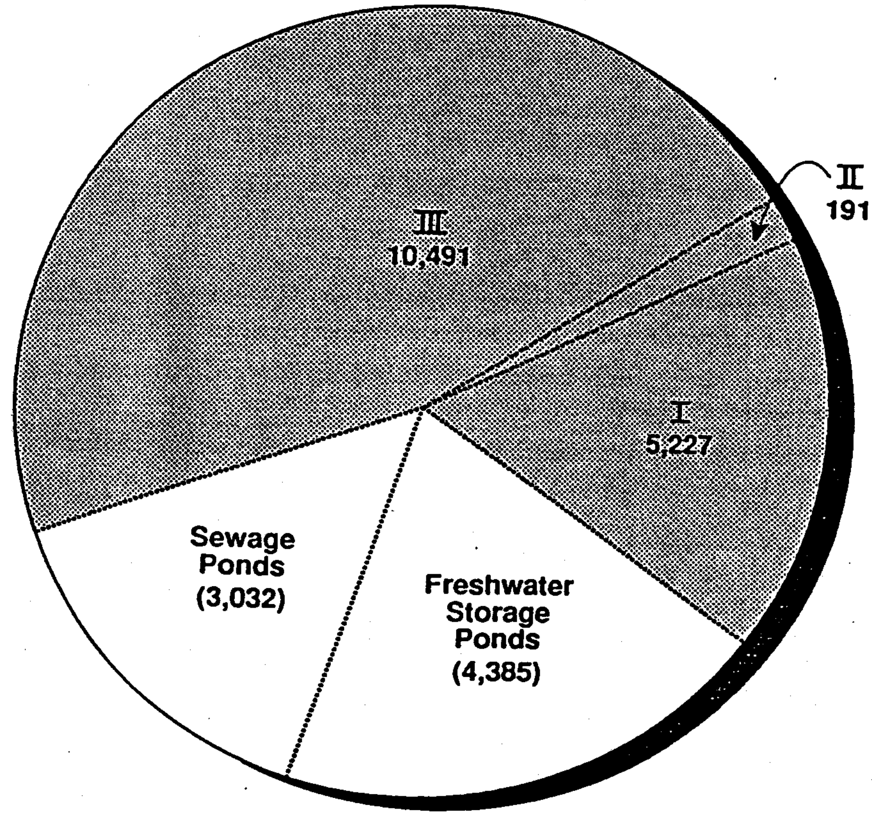
Regional Effects

During the nesting season, managed and natural wetlands in the region, including native habitats, duck clubs, and Kern National Wildlife Refuge, are largely without water. Evaporation basins provide approximately 67 percent of the available breeding season wetlands (Figure 5-5) of which about 39.6 percent is at sites with selenium levels that could have reproductive effects. No selenium data are available for two basins totaling 30 acres, so their status in Figure 5-5 and elsewhere in this report is considered unknown. These available wetland areas change with annual variation in water availability, land use, and flood conditions. In wet years (unlike those since 1986, when Tulare Basin bird studies began), substantially more area outside the evaporation basins may be flooded, but the areal extent is unknown. The distribution of shorebirds on the available habitats based on Sloat and Williams surveys is shown in Figure 5-6. These estimates indicate that about 45 percent of shorebirds occur at basins with selenium levels where reproductive effects could be predicted. These data included 1990 counts at 16 evaporation basins. Use of Sloat and Williams survey data is intended for comparison purposes only and should not be interpreted as representing an estimate of breeding populations. Large numbers of the birds seen in counts from May-July were migrants which breed in or near the Arctic. Breeding data are presented in Table 4-2, and estimates of breeding populations are presented in Table 2-8.

There were no data on the numbers of shorebirds expected on sewage treatment ponds and freshwater storage areas. The numbers in Figure 5-6 were, therefore, estimated using the same density as the evaporation basins. Thus, the estimate of the proportion of the regional shorebird population using evaporation basins is conservative.

Waterfowl nest at fewer evaporation basins than do shorebirds. Several basins (notably 11 and 22) support most of the known waterfowl nesting. The distribution of nesting grebes among major habitat types predicted from available information would be similar to that of nesting shorebirds. Most of the grebes observed at evaporation basins during spring and early summer were at Basin Nos. 11, 12, 21, and 22. However, the extent of waterfowl and grebe nesting in areas other than evaporation basins is not definitely known and, hence, the proportion of the regional breeding population at evaporation basins cannot be reliably estimated.

These discussions, and the estimates represented on Figures 5-5 and 5-6, demonstrate that during the breeding season, the evaporation basins represent a large proportion of the available breeding habitat in the area, and that a large percentage of the waterbirds present



Acres		Birds	
68.2%	Evaporation Basins [1]	15,908.2	68.2%
	Expected Effects:		
	III Hatchability & Teratogenicity	*10,490.6*	*45.0%*
	II Hatchability	*190.7*	*0.8%*
	I None	*5,226.9*	*22.4%*
		15,908.2	*68.2%*
0%	Natural Wetlands	0	0%
13.0%	Sewage Ponds	? (3,032.4)	13.0%
18.8%	Freshwater Storage Ponds	? (4,385.2)	18.8%
100%		23,325.8	100%

[1] Eighty-three percent of basins were surveyed

Figure 5-6
Monthly Average Spring-Summer (May - July) Waterbird Populations in the Tulare Basin, by Habitat Type

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at any time are found on the evaporation ponds. Additionally, using conservative estimates, a large percentage of the evaporation basins have selenium levels which could cause reproductive effects. Therefore, using the rationale discussed earlier, the potential reproductive effect of the evaporation basins on shorebirds and other waterbirds is a significant adverse cumulative impact.

Temporal Effects

Enlargement of existing basins or the construction of new basins to a total of around 9,000 acres would increase total area of evaporation basins by about 25 percent. Considering the prediction that a large percentage of current ponds have selenium levels which could adversely affect bird reproduction (Figure 5-6), increasing acreage could increase the amount of habitat with potentially adverse breeding effects.

BIRD HEALTH

Chapter 4 describes the potential adverse effects of evaporation basins on bird health and the known instances of avian botulism and fowl cholera in the region and at basins.

The factors that favor the precipitation of an outbreak of botulism in waterfowl include a prolonged spell of warm weather, enlarged areas of shallow stagnant water, alkalinity, an abundance of aquatic invertebrates, and oxygen depletion associated with large amounts of rotting vegetation or other organic matter (Smith 1982).

Botulism is caused by the ingestion of lethal neurotoxin produced by *Clostridium botulinum*, a bacterium whose natural habitat is soil and mud. The original contamination of a lake or waterway with any type of *Clostridium botulinum* could occur through the intermediary of waterbirds that fly from one aquatic environment to another. Any bird leaving a lake or pond on which an outbreak of avian botulism is in progress is likely to carry type C (the agent of avian botulism) spores on its external surfaces and in its alimentary tract (Haagsma, 1974; Smith, 1992).

The evaporation basins have not been shown to be the source of avian botulism, or other diseases. However, many of the factors which precipitate an outbreak occur at the basins. If a major outbreak of avian botulism occurred in the Tulare Lake Basin, then the evaporation basins could contribute to the spread of the disease. In aquatic areas where an outbreak has occurred, type C spores can be found in the mud for years afterwards.

The potential increase in evaporation basins to 9,000 acres could raise the total of warm, shallow wetland habitats with botulism potential to 250 to 3,990 acres. This range reflects 0 to 1,990 acres in addition to the 250 to 2,000 acres estimated by Ford and Young (1988).

WINTERING AND MIGRATING WATERBIRDS

Many waterfowl and shorebirds winter in and migrate through the study area. Some of these birds may be exposed to contaminated evaporation pond environments and may accumulate selenium and other substances. While extensive studies have not been completed to date, two sources provide limited information on concentrations of selenium in waterbird tissues during the winter. Barnum (unpublished) studied selenium concentrations in four species of ducks from Kern National Wildlife Refuge and nearby evaporation basins (Table 5-2). These data suggest that tissue selenium tends to be higher in individuals collected from evaporation basins than from those collected at the Kern Wildlife Refuge. Additionally ruddy ducks tend to have higher concentrations of selenium under these conditions than do the other three species.

Table 5-2
Mean Selenium Concentrations (ppm, wet weight) in Waterfowl Breast Tissue from Kern National Wildlife Refuge and Surrounding Evaporation Ponds, October 1988-March 1989

	Kern National Wildlife Refuge		Evaporation Ponds	
Species	Sample Size	Mean Selenium Concentration	Sample Size	Mean Selenium Concentration
Northern Shoveler	49	1.09	17	1.52
Northern Pintail	28	0.50	7	1.34
Ruddy Duck	10	1.07	49	2.67
Green-winged Teal	40	0.49	4	1.28

Source: D. Barnum, USFWS, unpubl. data.

Data also are available from the Selenium Verification Study (White, et al., 1987, 1989) and are summarized in Table 5-3. Tissue selenium levels from the selected species of waterbirds collected at evaporation basins were often below the 10 ppm dry weight liver concentration considered in this report to be the threshold of background concentrations. Ruddy ducks were the one exception as liver selenium concentrations at three evaporation basins were greater than 20 ppm. However, no verified instance of selenium toxicosis has been reported at any locale in the southern San Joaquin Valley. Adult wintering birds with symptoms similar to those of selenium toxicosis were observed but not evaluated, researched or formally reported (Barnum, pers. comm.).

When waterfowl shift from high-selenium diets to low-selenium diets they rapidly eliminate accumulated selenium (Heinz et al., 1990), and within a few weeks tissue concentrations reduce below the threshold for adverse reproductive effects as described in more detail in Chapter 4. This ability to eliminate selenium reduces the risks to migrating and wintering waterfowl populations. Similar data are not available at this time for shorebirds, however.

Table 5-3
Summary of Muscle and Liver Selenium Concentrations in Waterbirds from Evaporation Basins in the Southern San Joaquin Valley, Winter, 1986 (ppm wet weight)
(Source: White et al., 1987, 1989)

	Location		Muscle		Liver	
Species	Basin No.	Basin Name	Mean	SD	Mean	SD
Cinnamon Teal	22	Tulare Lake Drainage District South	1.5	0.76	5.7	3.13
	23	Westfarmers	0.92	0.53	4.9	2.39
	25	Lost Hills Ranch				
Ruddy Duck[ab]	23	Westfarmers	22	nr	45	nr
	14	Pryse	16	nr	59	nr
	12	Westlake Farms South	9.3	nr	31	nr
	9	Meyers Ranch	4.2	nr	12	nr
American Avocet	22	Tulare Lake Drainage District South	na	na	5.9	3.25
	23	Westfarmers	na	na	5.9	4.27
Black-necked Stilt	23	Westfarmers	na	na	15	nr[c]
	25	Lost Hills Ranch	na	na	5.1	3.32
American Coots	22	Tulare Lake Drainage District South	2.0	1.58	3.6	2.10
	25	Lost Hills Ranch	0.26		0.92	

[a] ppm, dry weight
[b] n=10, no standard deviation reported
[c] n=1.
na = no data
nr = not reported

Most waterfowl which winter in the southern San Joaquin Valley nest farther north (especially Alaska and Canada; Chapter 2). Precise information on the time elapsed between feeding in the southern San Joaquin Valley and beginning of nesting and egg-laying is not available. The ability to rapidly deplete body selenium, plus the distance between the southern San Joaquin Valley and major breeding areas, suggests a low potential for adverse reproductive effects in those species leaving high selenium evaporation ponds 1 to 2 weeks prior to breeding. However, no studies in the breeding grounds have been conducted, and speculation regarding these effects is highly controversial.

Similarly, there is some evidence (Barnum pers. comm.) that an indicator of body condition (Index = Body wt/Flat wing length) showed better condition (i.e., higher index) for wintering birds from some species from Kern NWR as compared to those from evaporation basins. If these data are supported by further study, this might have implications regarding differential survivorship during migration (another unstudied topic).

BENEFICIAL CUMULATIVE EFFECTS

BIRD REPRODUCTION

Selenium levels at 38 percent of the evaporation ponds, including nine basins (Basins 6, 8, 9, 10, 11, 12, 13, 24 and 25 for a total of 2,555 acres) are low enough to make reproductive effects unlikely (Figure 5-5), at least by the relatively conservative categories described earlier. If other toxic substances are also present at insignificant levels, these ponds may represent wetland habitat that is a realized or potential benefit to waterfowl and shorebirds.

In spring, 67 percent of available wetland habitat in the Tulare Basin is provided by the evaporation basins (Figure 5-5). Roughly 25 percent of the total available wetland habitat during the breeding season consists of evaporation basins with selenium concentrations below the predicted effect levels.

Additionally, there may be a number of successful nests (producing young that survive to later breed) each year at sites where selenium levels are above thresholds. While nest success rates are not known at this time, if a significant number of young survive at some contaminated sites and later reproduce, then the evaporation basins are a source of recruitment (i.e., they contribute to the population).

Again, no studies have been conducted which followed long-term survivorship of young which hatched at ponds with relatively high selenium levels. Thus, the probability that there has been a net benefit is controversial, and should be further studied. Incidental observations at some ponds suggest low recruitment (Skorupa, pers. comm). Chapter 4 described survivorship of young fed various levels of selenium in the diet.

Snowy plover nest densities and nesting success at evaporation ponds are equal to or greater than other sites (Roster et al., in press; Barnum et al., in press). Skorupa (unpubl. data) reports high hatching or nesting success of snowy plovers at most evaporation pond sites, but snowy plovers at one site (Basin No. 26) have reduced hatching success. Numbers of snowy plovers nesting at evaporation basins increased in the 1980's (Roster et al., in press). Page et al. (1991) review the current status of the snowy plover and determine that the increase in numbers nesting in the San Joaquin Valley is equivalent to a concomitant decrease in numbers in the Owens Valley. Snowy plovers observed in the San Joaquin Valley comprise 14 to 19 percent of all snowy plovers observed in interior population surveys during 1988. No studies have followed individual birds through time, so to date the overall contribution of the basins to snowy plover populations is not known.

BREEDING HABITAT

The anticipated closure of Basin Nos. 4, 7, 18, and 20 would eliminate approximately 220 acres of evaporation basin sites. No data are available for two of those basins, but Basins No. 4 and 7 have selenium concentrations in the range where reproductive effects might be detectable. Closure would remove 100 acres of habitat which has potential risks to waterbirds.

WINTERING AND MIGRATING WATERBIRDS

Pre-irrigated fields, especially small grains, are also an important component of waterfowl habitat in the southern San Joaquin Valley. These fields contribute about 15 percent of wetland waterfowl habitat in the Kern-Tulare Basin (Figure 5-7), and are used extensively by wintering waterfowl (Table 5-3, Figure 5-8). Waterfowl and shorebirds, as well as other waterbirds, opportunistically move into the fields as the pre-irrigated habitat becomes available.

However, no clear relationship has been documented between evaporation basins and the availability of pre-irrigated croplands to waterfowl. There has been a reduction of about 9,600 acres (36 percent) in small grains and alfalfa in the Tulare Basin from baseline 1970 to current conditions 1990. Jones and Stokes (1988) cite factors of irrigation water cost, and market changes influencing a shift from small grain to cotton production as the main factors in reducing pre-irrigated habitat. Barnum and Euliss (1991) suggest that increased drainage capability created by tiled drains and evaporation basins allows faster pre-irrigation, thus reducing the time pre-irrigated croplands are available. Additionally, they report an overall reduction of 30 to 60 percent in the average acreage of pre-irrigated lands available on given sample days from the 1976-1980 period to the 1981-1987 period.

UNKNOWN CUMULATIVE EFFECTS

The adverse and beneficial effects discussed earlier are those that have been reasonably demonstrated to exist, although in some cases these categorizations are controversial. In addition to these, there may be other effects that have not been demonstrated, but could exist. These "unknown" effects are discussed here. As used in this report, "unknown" effects are those that cannot be reliably assessed with current information, but are considered possible in light of current knowledge of evaporation basin conditions and the biology of

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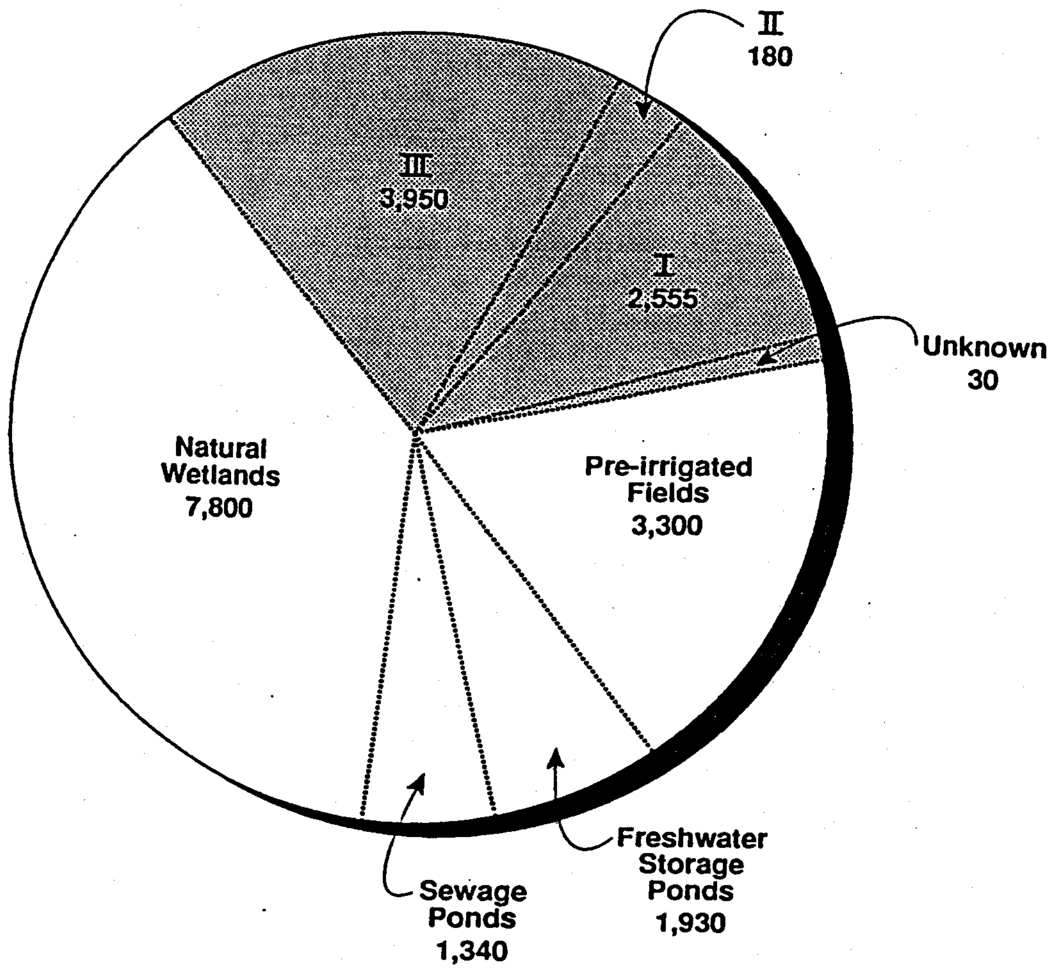

	Acres	
Evaporation Basins	6,715	31.8%
Expected Effects:		
III Hatchability & Teratogenicity	*3,950*	*18.7%*
II Hatchability	*180*	*0.8%*
I None	*2,555*	*12.1%*
Unknown	*30*	*0.1%*
	6,715	*31.8%*
Natural Wetlands	7,800	36.5%
Pre-irrigated Fields	3,300	15.4%
Sewage Ponds	1,340	6.3%
Freshwater Storage Ponds	1,930	9.0%
	21,085	100%

Figure 5-7
Acres of Wetland Habitat in the Tulare Basin during Fall/Winter (September - February), by Type

CH2M HILL

H. T. HARVEY & ASSOCIATES

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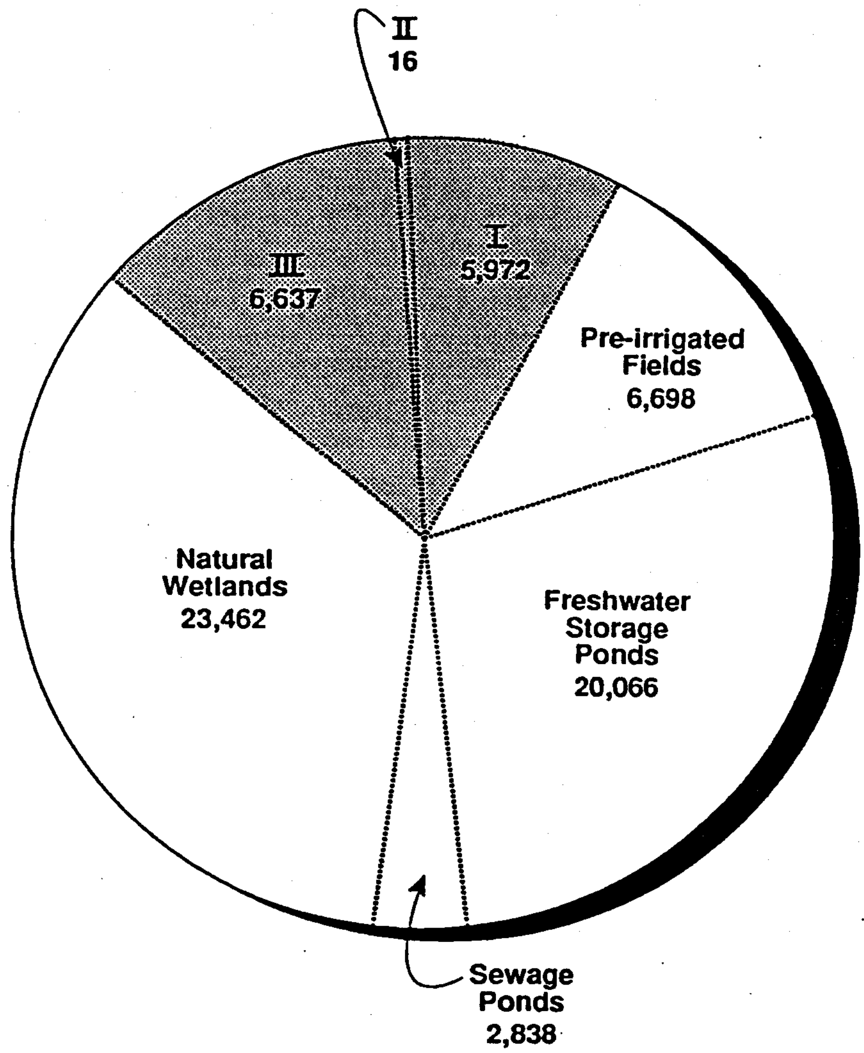


	Birds	
Evaporation Basins	12,625	19%
Expected Effects:		
III Hatchability & Teratogenicity	*6,637*	*10%*
II Hatchability	*16*	*<1%*
I None	*5,972*	*9%*
	12,625	*19%*
Natural Wetlands	23,462	35%
Sewage Ponds	2,838	5%
Pre-irrigated Fields	6,698	10%
Freshwater Storage Ponds	20,066	31%
	65,689	100%

Figure 5-8
Monthly Average Waterfowl Populations during Fall/Winter (September - April) in the Tulare Basin, by Habitat Type

CH2M HILL

affected organisms. Further study or monitoring would be required to determine whether these effects indeed exist.

BIRD REPRODUCTION AND HEALTH

Salinity

Field and laboratory studies of the effects of salinity to date have focused on magnesium and sodium sulfate concentrations and specific conductivity of water in natural saline wetlands (Chapter 3). Effects on ducklings were found at levels lower than those typically found in the Tulare Basin evaporation ponds. Although toxic effects could be expected in the evaporation basins, studies have not been conducted to assess their significance using the specific ion concentrations found in these waters. Most of the evaporation basins contain total dissolved solids at concentrations that are potentially toxic, especially to young birds. However, at some sites, inflow water and particular cells have salinities below potentially toxic concentrations (Wescot et al., 1988a).

Calcium carbonate deposition on ruddy duck tail feathers and resulting feather damage has been noted (Euliss et al. 1989) at some sites. This feather damage would reduce the ability of the ducks to fly or dive. Deposits of up to 30 percent of birds' body weight have been observed (Barnum, pers. comm. in Moore et al. 1990). The significance of calcium carbonate deposition and resultant feather erosion to ruddy duck populations is not known.

Trace Elements

The effects of concentrated drainwater constituents other than selenium on waterbird reproduction and health are not well-researched at evaporation basins. Concentrations of selected constituents in evaporation basins and their levels of effect are discussed in earlier chapters.

In the Tulare Basin, boron has been measured in the aquatic food chain at concentrations up to about 1,500 ppm and commonly exceeds 300 ppm (Moore et al., 1989). However, boron concentrations in the eggs of aquatic birds from the Tulare Basin (J. P. Skorupa, pers. comm.) are substantially lower than the adverse-effect threshold determined in experimental studies (Smith and Anders, 1989).

Vegetation from some Tulare Basin evaporation ponds consistently contained 50 to 150 ppm arsenic and sometimes up to 400 ppm (Moore et al., 1989), concentrations that could be harmful themselves or could influence selenium toxicity. The occurrence of vanadium at elevated concentrations in many evaporation basins may inhibit the ability of birds to tolerate high salinity drinking water. Aside from arsenic and boron, few studies have been conducted specifically to assess hazards of subsurface drainage water constituents to wildlife. Those waters, however, can also contain high concentrations of other trace elements including aluminum, molybdenum, uranium, and vanadium (Westcot et al., 1988a, 1988b).

Over time, the concentrations of salts and trace elements in an evaporation basin are expected to increase at least in some cells (Parker and Knight 1989). Thus, it is likely that the potential toxicity of ponds or portions of ponds would also increase. This might not be the case for those ponds draining service areas that lack selenium or other toxic substances in concentrations sufficient to generate significantly toxic concentrations in evaporation pond water. The net effect of this condition is difficult to predict; there is a possibility that concentrations of salts or other constituents in the ponds could reach levels that reduce or eliminate attractive invertebrate populations, thereby reducing or eliminating waterbird use. Bird use is known from sites with salinity of 200 to 300 parts per thousand (Bradford et al., 1989).

Disease

Mallard ducklings reared with 10 to 30 ppb waterborne selenium were more susceptible than controls to mortality from duck hepatitis (Whiteley and Yuill, 1989). It is possible that exposure of waterfowl to increased dietary selenium on evaporation basins could also increase mortality to avian botulism or cholera, but this possibility has not been studied.

REGIONAL POPULATIONS

The potential exists for long-term changes in regional populations of waterbirds that breed in significant proportions at evaporation basins. Few data are available for these breeding birds. Preliminary data compilations of breeding bird census data suggest that during the 1980's, black-necked stilt populations in the Sacramento Valley were increasing while those in the San Joaquin Valley remained about equal to those in the 1970's (PWRC, 1990b; USFWS, unpubl. data). Based on these preliminary analyses, there have been no statistically significant changes in avocet populations, but the data suggest a possible decline in the San Joaquin Valley during the 1980s. In contrast to those two species, there is no apparent trend in either area for killdeer. Although these initial analyses are inconclusive, the data are being examined in greater detail by the USFWS. Among the three species, the avocet (which is most strongly associated with saline environments) is the only one that has shown suggestive evidence of a regional population decline in the San Joaquin Valley. The magnitude and significance of this effect is unknown because the net regional population recruitment from various wetland breeding habitats is unknown.

WINTERING AND MIGRATING WATERBIRDS

The effects of evaporation ponds on wintering and migrating waterfowl are unknown. Some biologists argue that the ponds have high productivity, that many of the ponds or cells within ponds represent little risk, and that the numbers of birds using the sites alone is evidence of their benefit. Others argue that any exposure to selenium is detrimental, and that more birds simply means more risk. Clearly, this report cannot resolve the issue, but can only report what facts are known.

Evaporation basins may, in most years, represent much of the fall and winter wetland habitat present in the southern San Joaquin Valley. Evaporation basins provide, on the average, about 32 percent of fall and winter wetland habitats (Figure 5-7). This percentage is expected to vary annually with flood conditions and availability of irrigation water. About 19 percent of wintering and migratory waterfowl observed in the region over fall and winter (1983 to 1988) were using evaporation basins (Figure 5-8). Waterfowl use of evaporation basins ranged from 14 to 27 percent (7,000 to 17,000 birds) of regional populations per month (Jones and Stokes, 1988).

The use of different habitat types by principal waterfowl species in the region is depicted in Table 5-4. Evaporation ponds had the lowest densities of pintail, mallard and teals of the five wetland habitat types surveyed. Shovelers used evaporation ponds in intermediate densities. Only ruddy ducks were observed on evaporation basins in densities greater than on other habitats. Use of habitats as measured by waterfowl density varies over the winter, probably reflecting changes in factors such as habitat availability, food supplies, and dietary needs (Barnum and Euliss, in review).

Some evaporation basins may also serve as sanctuaries for waterfowl from hunting and other disturbances (Coe, 1990). Sanctuary areas are considered essential elements for waterfowl management (USFWS, 1986). However, some basins have been legally and illegally hunted (D. Mitchell, DFG, pers. comm). At this time, data are limited and it is not possible to assess the magnitude of this possible effect.

Table 5-4
Mean Density (Birds/Acre) of Wintering Ducks for Tulare Basin Wetlands, 1980-1987

Wetland Type	Pintail	Mallard	Teal	Shoveler	Ruddy Duck	Total
Kern NWR	5.5	0.4	2.1	1.4	0.04	9.8
Hunting Clubs	2.0	0.1	1.0	0.6	0.04	4.3
Pre-irrigated Cropland	9.7	0.2	0.1	0.9	0.1	11.2
Evaporation Ponds	0.9	0.02	0.1	0.8	0.8	2.9
Miscellaneous	1.8	0.2	0.02	0.3	0.3	3.0

Source: Barnum and Euliss, in review.

According to recent studies by PRBO, the evaporation ponds are also used by large numbers of migrant shorebirds. These ponds held 68,000 shorebirds in late July, and 50,000 in early September 1990 (D. Shuford, pers. comm.). They have also held 20,000 to 30,000 Wilson's phalarope, and comprise one of this species' four major staging areas in California (Jehl, 1988).

When combined with the waterfowl census data presented above, the evaporation ponds may not be just a simple "attractive nuisance" but may be significant wetland habitats, at least during some seasons. Although the evaporation basins were not intended to provide waterbird habitat, with 50,000 to 68,000 shorebirds and 7,000 to 17,000 wintering or migrating waterfowl using these ponds, clearly habitat has been provided.

While the use of these areas is clear, and reproductive effects on birds migrating north to breed appear unlikely, little or no data are available on other possible effects (i.e., increased mortality). More extensive and long-term studies are required to determine conclusively whether there is a net benefit. It should be noted that the types of studies that would be necessary to address these problems in nature would be, logistically, quite formidable (See also Chapter 4).

It has been postulated that the presence of the additional area of wetland habitat provided by the basins has functioned in concert with other habitats to increase use of the region by migrating and wintering birds. However, the effects of evaporation basins on waterbird distributions both in the southern San Joaquin Valley and in the Pacific Flyway are unknown.

The relatively permanent wetlands provided by the evaporation basin systems may buffer annual fluctuations in natural or agricultural habitats for waterbirds. The potential for this effect is demonstrated by some of the waterfowl surveys conducted in the southern San Joaquin Valley. Comparison of surveys conducted during seasons of varying flood conditions and water availability (Coe, 1990; Jones and Stokes, 1988; Sloat and Williams, unpubl. data) suggest that waterfowl may use evaporation basins when other habitat types are not available.

OTHER WILDLIFE

Cumulative effects on other wildlife are largely speculative, as little or no information exists to evaluate cumulative or site-specific impacts.

Drainwater constituents bioaccumulated in invertebrates at evaporation basins could result in reproductive and other effects on insectivorous birds and mammals (e.g., swallows and bats) feeding at evaporation ponds. Predators and scavengers (e.g., raptors, gulls, coyotes, snakes) foraging on waterbirds and their eggs at evaporation ponds could be affected by bioaccumulated drainwater constituents.

ORIGINAL

EXHIBIT I - 18

Preliminary Cost Analysis of Wet, Dry And Wet-Dry Hybrid Cooling Alternatives

For The

La Paz Generating Facility

December 10, 2001

Prepared by

J. Phyllis Fox, Ph.D.

On Behalf Of

Arizona Unions For Reliable Energy

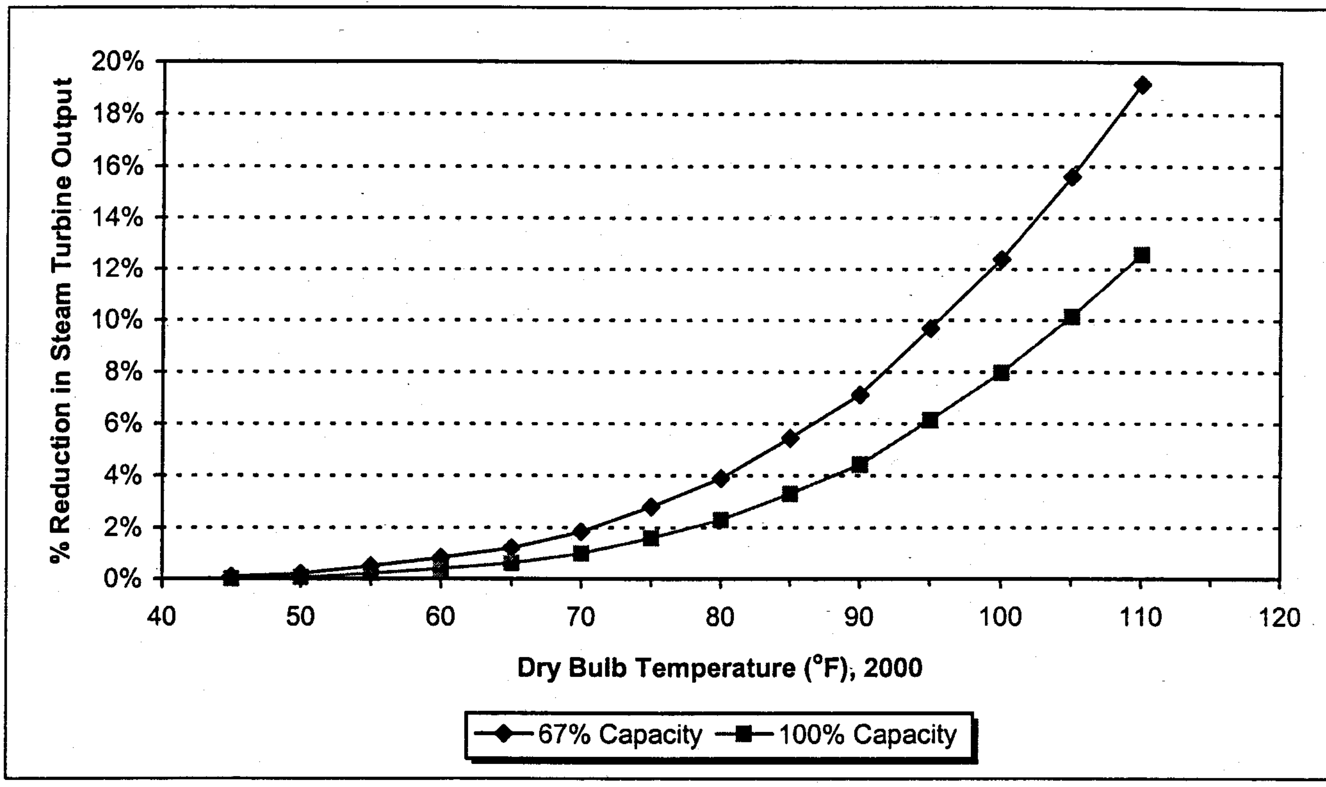
Table 1
Comparison of Cooling Water Alternatives
La Paz Generating Facility

	WET	DRY	WET-DRY
PERFORMANCE[a]			
No Supplemental Duct Firing			
Steam Turbine Gross	Base	-6.8% to -10.2%	-4.6% to -7.7%
Net Power	Base	-1.8% to -4.3%	-1.4% to -3.0%
Net Heat Rate	Base	1.9% to 4.5%	1.4% to 3.1%
Supplemental Duct Firing			
Steam Turbine Gross	Base	-0.4% to 2.0%	-0.8 to 0.9%
Net Power	Base	0.0% to -0.1%	-0.2% to 0.2%
Net Heat Rate	Base	2.8% to 5.7%	0.9%
ENVIRONMENTAL			
Water			
Water Use	Base	- 90% to - 95%	- 40% to - 60%
Wastewater	Base	None	-50%
Water Quality	Elevated As, F in ponds	None	Elevated As, F in ponds
Air Emissions			
Plume Downwash	Base	No change	No change
Combustion Emissions	Base	4.5% to 5.7%	0.1% to 3.1%
PM10 Drift	46 ton/yr	0	20 ton/yr
Cooling Tower Plume Visibility	Significant	None	Minor
Noise at 3 ft			
Mechanical	82 dBA	88 dBA	84 dBA
Splash	82 dBA	0 dBA	90 dBA
Composite	92 dBA	88 dBA	91 dBA
Other			
Land	1.7 ac	2.1 ac	1.9 ac
Permitting	Complex	Minimal	Complex
MAINTENANCE			
Heat Transfer Surface Life	10 yrs	30 yrs	10 yrs/30yrs
Structure Life	15 yrs (wood)	30 yrs (galvanized steel)	15yrs/30yrs
Long-Term Performance Loss	10% to 30%	0% to 3%	
Cleanability	Shutdown and repack	On-line automatic	
Maintenance Cost	High	Low	Medium
COSTS			
Capital ($million)	67	64	62
Incremental Cost ($million/yr)	Base	3.3 to 12.2	-0.5 to 8.6
Incremental Cost ($/MWh)	Base	0.48 to 1.79	-0.07 to 1.26

a Range corresponds to an annual average of 59°F/60% RH to 98°F/28% RH.

J. Phyllis Fox, PhD
12/10/2001

Figure 1
Effect of Ambient Dry Bulb Temperature on Steam Turbine Output



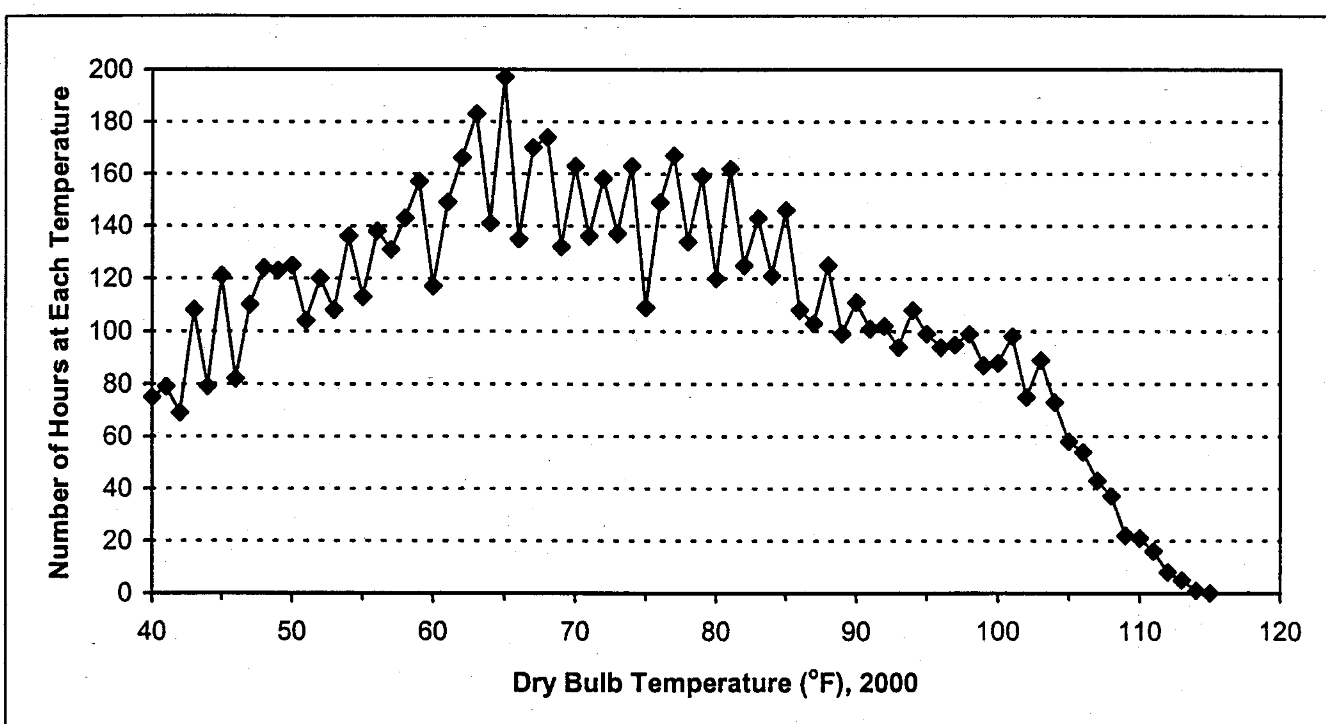


Table 2A
Cost Comparison of Cooling Water Alternatives, No Supplemental Duct Firing
(-30% to +30% Estimate)

Plant Performance Summary	Wet Cooling	Dry Cooling	Wet/Dry Cooling
Plant Performance Summary			
Net power output, MW			
Average[a]	1,157	1,122	1,132
Incremental	(base)	-36	-25
Total fuel consumed, 10^6 Btu/hr (HHV)			
Average[a]	8,197	8,459	8,377
Incremental	(base)	262	180
Cost Summary			
Cooling system capital cost ($million)[b]	67	62	59
Incremental ($million)	(base)	-5	-8
Cooling system O&M[c] ($million/yr)	2.7	0.2	1.4
Incremental annualized costs ($million/yr)			
Cooling system capital recovery		-0.5	-0.8
Fuel		4.6	3.2
Cooling O&M[c]		-2.5	-1.3
Lost electricity generation		10.5	7.5
Incremental Cost ($million/yr)		**12.2**	**8.6**
Incremental Cost ($/MWh)		**1.79**	**1.26**
Plant Revenue ($million/yr)	**340**	**329**	**332**
% of Base Revenue		**3.6%**	**2.5%**
Basis			
Plant capacity factor[d]	0.67		
Simple capital recovery			
Term, yrs	20		
Rate	7.00%		
Capital recovery factor	0.0944		
Fuel cost, $/10^6 Btu	3.00		
Incremental power, $/MW-hr[e]	50.00		

a For wet case, Black Veatch Corp. Heat Balance, August 13, 2001,Case 6, base load, average temperature (72 F) with duct firing as reported in Class I Permit Application, La Paz Generating Facility, October 2, 2001. Changes in net power output and heat rate for dry and wet/dry cases based on AZURE Response to Data Request A-54, Attach. 6, average of range summarized on Table 1.

b Total project costs from Tables 4 and 5 adjusted to exclude supplemental duct burners.

c Estimated from $y = -4E\text{-}06\, x^2 + 10.617x + 2055.2$ (EPA 11/01, Table 2-19) for x = 134,590 gpm for the wet case and x = 58,900 gpm for the wet-dry case for two towers. O&M costs do not include 10% to 30% degradation in performance over life of wet tower. (EPA 11/01, p. 3-10.)

e Response to Data Request I-51.

Table 2B
Cost Comparison of Cooling Water Alternatives, Supplemental Duct Firing
(-30% to +30% Estimate)

Plant Performance Summary	Wet Cooling	Dry Cooling	Wet/Dry Cooling
Plant Performance Summary			
Net power output, MW			
Average[a]	1,157	1,157	1,157
Incremental	(base)	0	0
Total fuel consumed, 10^6 Btu/hr			
Average[a]	8,197	8,541	8,271
Incremental	(base)	344	74
Cost Summary			
Cooling system capital cost ($million)[b]	67	64	62
Incremental ($million)	(base)	-3	-5
Cooling system O&M[c] ($million/yr)	2.7	0.2	1.4
Incremental annualized costs ($million/yr)			
Cooling system capital recovery		-0.3	-0.5
Fuel		6.1	1.3
Cooling water O&M[c]		-2.5	-1.3
Lost electricity generation		0.0	0.0
Incremental Cost ($million/yr)		**3.3**	**-0.5**
Incremental Cost ($/MWh)		**0.48**	**-0.07**
Plant Revenue ($million/yr)	**340**	**340**	**340**
% of Base Revenue		**1.0%**	**-0.1%**
Basis			
Plant capacity factor[d]	0.67		
Simple capital recovery			
Term, yrs	20		
Rate	7.00%		
Capital recovery factor	0.0944		
Fuel cost, $/$10^6$ Btu	3.00		
Incremental power, $/MW-hr[e]	50.00		

a For wet case, Black Veatch Corp. Heat Balance, August 13, 2001,Case 6, base load, average temperature (72 F) with duct firing as reported in Class I Permit Application, La Paz Generating Facility, October 2, 2001. Changes in net power output and heat rate for dry and wet/dry cases based on AZURE Response to Data Request A-54, Attach. 6, average of range summarized on Table 1.

b Total project costs from Tables 4 and 5.

c Estimated from $y = -4E-06\ x^2 + 10.617x + 2055.2$ (EPA 11/01, Table 2-19) for x = 134,590 gpm for the wet case and x = 58,900 gpm for the wet-dry case for two towers. O&M costs do not include 10% to 30% degradation in performance over life of wet tower.

d Average capacity factor for combined-cycle plants based on industry survey. (EPA 11/01, p. 3-10.)

e Response to Data Request I-51.

Table 3
WET COOLING
Preliminary - Not for Construction

DESCRIPTION	QUANTITY Total	QUANTITY Unit	MAN HOURS Prod Mult	MAN HOURS Chart MH's	MAN HOURS Jobsite MH's	Wage Rate	TOTAL COSTS Labor	TOTAL COSTS Sub-Contract	TOTAL COSTS Material	TOTAL COSTS Total
						$	$	$	$	$
Piles	350	EA	1.25					568,800		568,800
Excavation/Backfill	18,180	CY	1.25	2,800	3,500	$ 23.34	81,690		22,000	103,690
Pump Pits & Skid Fdns	830	CY	1.25	4,150	5,188	$ 24.24	125,745		158,500	284,245
Cooling Tower Basins	4,200	CY	1.25	29,820	37,275	$ 24.24	903,546		714,000	1,617,546
C.T. Pit Steel	40	TON	1.25	1,000	1,250	$ 24.24	30,300		60,000	90,300
Cooling Towers[a]	2	EA	1.25					6,700,000		6,700,000
Surf Condenser	2	EA	1.25	10,000	12,500	$ 26.17	327,125		3,740,000	4,067,125
CCW Heat Exchanger	4	EA	1.25	400	500	$ 26.17	13,085		208,000	221,085
Circulating CW Pumps	6	EA	1.25	1,200	1,500	$ 26.17	39,255		1,872,000	1,911,255
Auxiliary CW Pumps	4	EA	1.25	300	375	$ 26.17	9,814		270,400	280,214
CT Makeup Pumps	2	EA	1.25	130	163	$ 26.17	4,253		37,400	41,653
Closed Loop CW Pumps	4	EA	1.25	460	575	$ 26.17	15,048		228,800	243,848
Chemical Injection Skid	1	EA	1.25	300	375	$ 26.17	9,814		118,000	127,814
C.T. Fire Protection	1	EA				$ 26.17		267,500		267,500
Water Treatment System[b]	1	EA				$ 26.17		4,630,000		4,630,000
Evaporation Ponds - Land[c]	60	AC						30,000		30,000
Evaporation Ponds - Construction[c]	60	AC						7,200,000		7,200,000
Land for Water Rights[d]	2,165	AC						9,300,000		9,300,000
Land for Cooling Towers[e]	1.7	AC						850		850
Water Supply Wells[f]	5	EA						3,692,000		3,692,000
Incremental Tank Costs[g]	12	EA						50,000		50,000
Permitting[h]								200,000		200,000
Hoists-C.T. Screens (5-ton manual ea.)	2	EA	1.25	200	250	$ 26.17	6,543		31,200	37,743
Piping-CWS/CWR, MU, BD	12,430	LF	1.25	34,520	43,150	$ 25.97	1,120,606		1,172,500	2,293,106
Electrical PDC & Aux Xfmr-Equip & Bulks	1	EA	1.25	14,170	17,713	$ 25.61	453,617		1,417,100	1,870,717
Paint (Pipe)						$ 25.97		157,000		157,000
Scaffolding			1.25	8,350	10,438	$ 25.54	266,574			266,574
Ladders							85,200			85,200
Extended Work Week, Casual OT @ 2%	15.63%						545,833			545,833
Total Direct Field Costs				107,800	134,750		4,038,046	32,796,150	10,049,900	46,884,096
Temp. Construction Facilities										
Constr. Svcs., Supplies, Exp.										
Field Staff, Subs. & Exp.										
Payroll, B&B, & Insurance										
Construction Equipment										
Small Tools										
Field Overhead Costs										
Indirect Field Costs	166% x Labor									6,703,156
Commissioning	1.26% x Direct Field Costs - Land Costs + Indirect Field Costs									557,631
Total Field Cost										54,144,882
Field Support & Construction										
H.O. Construction Support										
Project Management										
Engineering & Design										
Procurement										
H.O. Expenses										
H.O. Payroll & B&B										
H.O. Overhead Costs										
Total Home Office Costs	15.00% x Total Field Cost - Subcontracts - Land Costs									1,802,682
Total Field and Office Costs										55,947,564
Sales Tax	6.60% x Total Direct Field Material + 60% S/C + 10% IFC									2,006,262
Escalation	6.00% x Total Field & Office Costs - Land Costs + Sales Tax									2,917,379
Contingency	4.80% x Total Field & Office Costs - Land Costs + Sales Tax + Escalation									2,473,937
Warranty (Allowance or %)	0.1276% x Total Field & Office Costs - Land Costs + Sales Tax + Escalation + Contingency									68,922
Fee	6.00% x Total Field & Office Costs - Land Costs + Escalation + Contingency									3,120,482
TOTAL PROJECT COSTS										66,534,546
									Round to:	67,000,000

a Costed at $25/gpm (EPA 11/01, p. 2-28) based on a circulating water flow rate of 134,590 gpm and a design approach of 10.88°F (Response to Data Request I-52). See also AZURE Response to Data Request A-30, Attach-2.

b Response to Data Request I-50(j). Costs do not include high efficiency drift eliminator.

c 60 acres of ponds at $120,000/acre for construction and $500/acre for land costs, based on Response to Data Request I-50(a).

d Cost to purchase 2,165 acres of land to secure water rights, based on Response to Data Request I-50(i) and a nonrefundable option fee of $300,000 for an additional 160 acres, as reported at www.picoholdings.com/Allegheny.htm. Vidler reports the cash purchase price at approximately $9.1 million.

e 1.7 acres x $500/acre. Land area based on Siting Application, Ex. G-1. Land cost based on Response to Data Request I-50(a).

f Five 869-gpm wells, including pumps, pipeline, and installation, based on Response to Data Request I-50(e). Note that pump size in Response to Data Request I-50(e) is incorrectly stated as 569 gpm. Actual pump size would be 869 gpm, based on a maximum water demand of 6,500 ac-ft/yr (4,030 gpm).

g The increase in the cost of tanks for a wet system, compared to a dry system, based on Response to Data Request I-50(h).

h Aquifer protection permit, based on Response to Data Request I-50(k).

Table 4
DRY COOLING
Preliminary - Not for Construction

DESCRIPTION	QUANTITY Total	QUANTITY Unit	MAN HOURS Prod Mult	MAN HOURS Chart MH's	MAN HOURS Jobsite MH's	Wage Rate	TOTAL COSTS Labor	TOTAL COSTS Sub-Contract	TOTAL COSTS Material	TOTAL COSTS Total
							$	$	$	$
Piles	240	EA	1.25					390,000		390,000
Excavation/Backfill	623	CY	1.25	140	175	$ 23.34	4,085			4,085
Air Cooler Foundations	136	CY	1.25	3,210	4,013	$ 24.24	97,263		23,700	120,963
Air Cooler Pipe Support Foundations	3	CY	1.25	80	100	$ 24.24	2,424		600	3,024
Pipe Supports - Tee Supports	4	TON	1.25	80	100	$ 25.04	2,504		4,900	7,404
Air-Cooled Surface Condensers[a]	2	EA	1.25			$ 26.17		32,314,000		32,314,000
ACC Mechanical Erection[b]								8,078,500		8,078,500
Land for ACC[c]	2.1	AC							1,050	1,050
Auxiliary Air Coolers	4	EA	1.25			$ 26.17		857,000		857,000
STG/HRSG/BFW & Cond Pumps, Base Case						$ 26.17		3,300,000	-2,789,000	511,000
Duct Burner (supplemental firing)	4	EA						2,200,000		2,200,000
Piping Erection	1	LOT	1.25	200	250	$ 25.97	6,493			6,493
Electrical PDC & Aux Xfmr-Equip & Bulks	1	EA	1.25	12,470	15,588	$ 25.61	399,196		1,577,100	1,976,296
Water Supply Wells[d]	2	EA						1,020,000		1,020,000
Evaporation Ponds[e]	0	AC						0		0
Water Treatment System[f]	1	EA						2,290,000		2,290,000
Scaffolding			1.25	1,360	1,700	$ 25.54	43,418			43,418
Adders							13,900			13,900
Extended Work Week, Casual OT @ 2%	15.63%						88,979			88,979
Total Direct Field Costs				17,540	21,925		658,261	50,449,500	-1,181,650	49,926,111
Temp. Construction Facilities										
Constr. Svcs., Supplies, Exp.										
Field Staff, Subs. & Exp.										
Payroll, B&B, & Insurance										
Construction Equipment										
Small Tools										
Field Overhead Costs										
Indirect Field Costs	166% x Labor									1,092,713
Commissioning	1.26% x Direct Field Costs - Land Costs + Indirect Field Costs									642,824
Total Field Cost										51,661,647
Field Support & Construction										
H.O. Construction Support										
Project Management										
Engineering & Design										
Procurement										
H.O. Expenses										
H.O. Payroll & B&B										
H.O. Overhead Costs										
Total Home Office Costs	25.00% x Total Field Cost - Subcontracts - Land Costs									1,211,097
Total Field and Office Costs										52,872,744
Sales Tax	6.60% x Total Direct Field Material + 60% S/C + 10% IFC									1,927,023
Escalation	6.00% x Total Field & Office Costs + Sales Tax									3,287,986
Contingency	4.80% x Total Field & Office Costs + Sales Tax + Escalation									2,788,212
Warranty (Allowance or %)	0.1276% x Total Field & Office Costs + Sales Tax + Escalation + Contingency									77,678
Fee	6.00% x Total Field & Office Costs + Escalation + Contingency									3,536,937
TOTAL PROJECT COSTS										64,490,580
									Round to:	64,000,000

a BDT quote dated 10/15/01 provided by Allegheny (Wiley 12/6/01).

b Assumed to be provided by ACC vendor and costed at 25% of ACC Capital, based on AZURE Response to I-28, BDT quote attached to High Desert Analysis.

c 2.1 acres x $500/acre. Land area based on BDT quote dated 10/15/01provided by Allegheny (Wiley 12/6/01).

d Two 868-gpm wells, including pumps, pipeline, and installation, based on Response to Data Request I-53(d).

e The facility will generate cooling tower blowdown, boiler blowdown, sanitary waste, water treatment residuals, equipment washdown, miscellaneous drain wastewaters, and stormwater runoff. Typically, cooling tower blowdown comprises 90% of these wastes. The balance is routinely recycled within the plant or otherwise disposed. La Paz will collect stormwater runoff in a retention pond (Siting Application, Ex. G-1). Blowdown from a media evaporative cooling system, if any, can be eliminated by replacing it with a cheaper and more effective fogging system. Therefore, the only waste stream that must be discharge into the ponds is cooling tower blowdown. Thus, in a dry system, there is no need for evaporation ponds.

f Response to Data Request I-53(g).

Table 5
WET-DRY COOLING
Preliminary - Not for Construction

DESCRIPTION	QUANTITY Total	QUANTITY Unit	MAN HOURS Prod Mult	MAN HOURS Chart MH's	MAN HOURS Jobsite MH's	Wage Rate	TOTAL COSTS Labor	TOTAL COSTS Sub-Contract	TOTAL COSTS Material	TOTAL COSTS Total
							$	$	$	$
Piles	300	EA	1.25		-			487,500		487,500
Excavation/Backfill	71,609	CY	1.25	11,218	14,023	$ 23.34	327,285		22,000	349,285
Pump Pits & Skid Fdns	580	CY	1.25	2,910	3,638	$ 24.24	88,173		110,800	198,973
Cooling Tower Basins	2,520	CY	1.25	17,890	22,363	$ 24.24	542,067		428,400	970,467
Air Cooler Foundations	68	CY	1.25	1,610	2,013	$ 24.24	48,783		11,900	60,683
Air Cooler Pipe Support Foundations	2	CY	1.25	60	75	$ 24.24	1,818		400	2,218
C.T. Pit Steel	28	TON	1.25	700	875	$ 24.24	21,210		42,000	63,210
Air-Cooled Surface Condensers	2	EA	1.25			$ 26.17		14,100,000		14,100,000
ACC Mechanical Erection[a]										
Cooling Towers[b]	2	EA	1.25					2,900,000		2,900,000
Surf Condenser	2	EA	1.25	6,000	7,500	$ 26.17	196,275		1,760,000	1,956,275
Duct Burner (supplemental firing)	4	EA						2,200,000		2,200,000
CCW Heat Exchanger	4	EA	1.25	400	500	$ 26.17	13,085		208,000	221,085
Circulating CW Pumps	6	EA	1.25	560	700	$ 26.17	18,319		1,169,000	1,187,319
Auxiliary CW Pumps	4	EA	1.25	180	225	$ 26.17	5,888		270,400	276,288
CT Makeup Pumps	2	EA	1.25	80	100	$ 26.17	2,617		37,400	40,017
Closed Loop CW Pumps	4	EA	1.25	390	488	$ 26.17	12,758		257,900	270,658
Chemical Injection Skid	1	EA	1.25	200	250	$ 26.17	6,543		70,800	77,343
C.T. Fire Protection	1	EA				$ 26.17		840,000		840,000
Water Treatment System[c]	1	EA				$ 26.17		2,315,000		2,315,000
Evaporation Ponds - Land[c]	30	AC						15,000		15,000
Evaporation Ponds - Construction[c]	30	AC						3,600,000		3,600,000
Land for Water Rights[c]	1,082.5	AC						4,650,000		4,650,000
Land for Cooling Towers/ACC[d]	1.9	AC						950		950
Water Supply Wells[e]	3	EA						2,215,200		2,215,200
Incremental Tank Costs[c]	12	EA						25,000		25,000
Permitting[f]								200,000		200,000
Hoists-C.T. Screens (5-ton manual ea.)	2	EA	1.25	50	63	$ 26.17	1,636		5,200	6,836
STG/HRSG/BFW & Cond Pumps, Base Case						$ 26.17		3,300,000	-3,089,000	211,000
Piping-CWS/CWR, MU, BD	7,460	LF	1.25	20,710	25,888	$ 25.97	672,298		703,500	1,375,798
Electrical PDC & Aux Xfmr-Equip & Bulks	1	EA	1.25	18,340	22,925	$ 25.61	587,109		2,049,300	2,636,409
Paint (Pipe)						$ 25.97		94,200		94,200
Scaffolding			1.25	6,830	8,538	$ 25.54	218,048			218,048
Adders							69,100			69,100
Extended Work Week, Casual OT @ 2%	15.63%						442,800			442,800
Total Direct Field Costs				88,128	110,160		3,275,812	36,942,850	4,058,000	44,276,662
Temp. Construction Facilities										
Constr. Svcs., Supplies, Exp.										
Field Staff, Subs. & Exp.										
Payroll, B&B, & Insurance										
Construction Equipment										
Small Tools										
Field Overhead Costs										
Indirect Field Costs	166% x Labor									5,437,847
Commissioning	1.26% x Direct Field Costs - Land Costs + Indirect Field Costs									567,612
Total Field Cost										50,282,120
Field Support & Construction										
H.O. Construction Support										
Project Management										
Engineering & Design										
Procurement										
H.O. Expenses										
H.O. Payroll & B&B										
H.O. Overhead Costs										
Total Home Office Costs	15.00% x Total Field Cost - Subcontracts - Land Costs									1,300,998
Total Field and Office Costs										51,583,119
Sales Tax	6.60% x Total Direct Field Material + 60% S/C + 10% IFC									1,766,655
Escalation	6.00% x Total Field & Office Costs - Land Costs + Sales Tax									2,921,029
Contingency	4.80% x Total Field & Office Costs - Land Costs + Sales Tax + Escalation									2,477,033
Warranty (Allowance or %)	0.1276% x Total Field & Office Costs - Land Costs + Sales Tax + Escalation + Contingency									69,008
Fee	6.00% x Total Field & Office Costs - Land Costs + Escalation + Contingency									3,138,914
TOTAL PROJECT COSTS										61,955,758
									Round to:	62,000,000

a Assumed to be provided by ACC vendor and costed at 25% of ACC Capital, based on AZURE Response to I-28, BDT quote attached to High Desert Analysis.

b Costed at \$25/gpm (EPA 11/01, p. 2-28) based on a circulating water flow rate of 58,900 gpm and a design approach of 10.88°F (Response to I-52). See also AZURE Response to Data Request A-30, Attach-2.

c Costed at 50% of wet case.

d Sum of 50% wet case area (1.7 ac) and 50% dry case area (2.1 ac) costed at \$500/acre.

e Costed at 3/5 of wet case.

f Aquifer protection permit, based on Response to Data Request I-50(k).

Supporting Materials

DUKE / FLUOR DANIEL

COMPARATIVE ANALYSIS OF WET, DRY AND WET-DRY HYBRID COOLING ALTERNATIVES

Prepared by Duke/Fluor Daniel

For

Mountainview Power Company LLC

July, 2000

DUKE / FLUOR DANIEL

ESTIMATE BASIS & ASSUMPTIONS

◆

WET COOLING CASE:

◆ THE GENERAL APPROACH WAS TO PRIMARILY UTILIZE THE MAJOR PORTION OF COST DATA FROM THE LUMP SUM TURNKEY DETAIL ESTIMATE FOR THE TOTAL POWER PLANT. DIRECT FIELD COST COMPONENTS SUCH AS PILING, COOLING TOWER BASIN/PUMP PITS CONCRETE, MECHANICAL EQUIPMENT PRICING FOR ALL PUMPS, CHEMICAL INJECTION SYSTEM, WATER SOFTENER SYSTEM, HOIST AND FIRE PROTECTION PACKAGE, PIPING, PAINTING, SCAFFOLDING, ETC. WERE TAKEN DIRECTLY FROM THE DETAIL TOTAL PLANT ESTIMATE BACKUP AND SUMMARIZED SEPARATELY TO ISOLATE THE COOLING TOWER SYSTEM COSTS FOR THIS WET COOLING BASE CASE.

◆ MECHANICAL EQUIPMENT PRICING WAS DONE IN-HOUSE FOR THE COOLING TOWERS, SURFACE CONDENSERS AND CCW HEAT EXCHANGERS.

◆ A SEPARATE COST FOR AN ELECTRICAL POWER DISTRIBUTION CENTER WITH AUXILIARY TRANSFORMERS WAS ADDED TO THE COOLING TOWER SYSTEM DIRECT FIELD COST. THIS ELECTRICAL COST WAS ESTIMATED USING A POWER DISTRIBUTION COST FROM A RECENT SAME SIZE POWER PLANT COOLING OPTION STUDY BY ADJUSTING IT TO THE TOTAL REQUIRED CONNECTED KW LOADING FOR THIS CASE.

◆ ALL OTHER COSTS BELOW THE DIRECT FIELD COST LINE SUCH AS INDIRECTS, HOME OFFICE ENGINEERING, SALES TAX, CONTINGENCY, ETC. WERE DERIVED FROM THE TOTAL PLANT DETAIL ESTIMATE DATA AND INCLUDED AS FACTORED OR PERCENTAGE COSTS.

DRY COOLING CASE:

◆ THE GENERAL APPROACH FOR THIS CASE WAS TO PRIMARILY UTILIZE THE MAJOR PORTION OF COST DATA FROM A RECENT SAME SIZE POWER PLANT COOLING STUDY FOR AN AIR COOLED CONDENSER (DRY) COOLING OPTION. IT WAS ASSUMED THAT THE AIR COOLED CONDENSERS IN THIS REFERENCE PLANT COST HAD THE SAME COOLING CAPACITY AS IS REQUIRED FOR THIS CASE. THEREFORE ALL DIRECT FIELD COST COMPONENTS SUCH AS PILING, EXCHANGER FOUNDATIONS, STRUCTURAL STEEL SUPPORTS, EQUIPMENT ERECTION, PIPING, ETC. WERE USED DIRECTLY FROM THIS REFERENCE COOLING STUDY ESTIMATE. IT WAS ASSUMED IN THIS STUDY THAT THE AIR COOLED CONDENSERS WILL BE IN CLOSE PROXIMITY TO THE STEAM TURBINE EXHAUST SO THAT THERE WILL BE MINIMAL PIPING COSTS WITHIN THIS COOLING SYSTEM BOUNDARY.

◆ MECHANICAL EQUIPMENT PRICING WAS DONE IN-HOUSE FOR THE AIR COOLED CONDENSERS AND AUXILIARY AIR COOLERS.

- IN-HOUSE PRICING WAS DONE FOR THE STEAM TURBINE GENERATORS, HRSG'S AND ASSOCIATED EQUIPMENT (BFW AND CONDENSATE PUMPS, FIREWATER STORAGE TANK, ETC.) IMPACTED BY CHANGES TO THE TOTAL PLANT PRODUCTION REQUIREMENTS FOR THIS CASE. A PRICE DELTA WAS THEN DETERMINED FOR THESE EQUIPMENT SERVICES FOR THIS CASE VERSUS THE BASE CASE AND INCLUDED IN THE COST ESTIMATE.

- A SEPARATE COST FOR AN ELECTRICAL POWER DISTRIBUTION CENTER WITH AUXILIARY TRANSFORMERS WAS ADDED TO THE AIR COOLED CONDENSER SYSTEM DIRECT FIELD COST. THIS ELECTRICAL COST WAS ESTIMATED USING A POWER DISTRIBUTION COST FROM THE REFERENCE POWER PLANT COOLING OPTION STUDY BY ADJUSTING IT TO THE TOTAL REQUIRED CONNECTED KW LOADING FOR THIS CASE.

- ALL OTHER COSTS BELOW THE DIRECT FIELD COST LINE WERE ESTIMATED IN THE SAME WAY AS THE BASE CASE (WET CASE) ABOVE.

WET - DRY COOLING CASE:

- THE OVERALL APPROACH FOR THIS CASE WAS TO CAPACITY ADJUST THE DIRECT FIELD COST COMPONENTS LISTED IN THE FIRST TWO CASES TO REFLECT THE REDUCTION IN THE SIZE OF THE COOLING TOWERS AND AIR COOLED CONDENSERS FOR THIS CASE.

- MECHANICAL PRICING WAS DONE IN-HOUSE PRIMARILY FOR THE COOLING TOWERS, SURFACE CONDENSERS, AIR COOLED CONDENSERS, CCW HEAT EXCHANGERS.

- IN-HOUSE PRICING WAS DONE FOR THE STEAM TURBINE GENERATORS, HRSG'S AND ASSOCIATED EQUIPMENT (BFW AND CONDENSATE PUMPS, ETC.) IMPACTED BY CHANGES TO THE TOTAL PLANT PRODUCTION REQUIREMENTS FOR THIS CASE. A PRICE DELTA WAS DETERMINED FOR THESE EQUIPMENT SERVICES FOR THIS CASE VERSUS THE BASE CASE AND INCLUDED IN THE COST ESTIMATE.

- COSTS WERE INCLUDED FOR THE ELECTRICAL POWER DISTRIBUTION CENTER WITH AUXILIARY TRANSFORMERS BY ADJUSTING THE REFERENCE SOURCE COSTS USED IN THE WET AND DRY CASES ACCORDINGLY FOR KW CAPACITY.

- ALL OTHER COSTS BELOW THE DIRECT FIELD COST LINE WERE ESTIMATED IN THE SAME WAY AS THE BASE CASE (WET CASE) ABOVE.

Cooling Tower
Water and Chemical Usage

82F / 34% RH Case

	Cooling Tower Configuration		
Water Rates:	Wet Cooling	Dry Cooling	Wet-Dry Clg.
	GPM		
CT Makeup	4830	0	2368
CT Blowdown	200	0	123
Chemicals Usage:	Chemical Costs/Year		
Sidestream Clarification-			
Soda Ash			
Magnesium Sulfate			
Sodium Hydroxide			
Est. Total Chemical Cost	$ 420,000	0	$ 220,000
Cooling Tower-			
Sulfuric Acid			
Scale/Corrosion Inhibitor			
Est. Total CT Chemical Cost	$ 480,000	0	$ 240,000

Notes:

1 Water rates and chemical cost estimates are preliminary for evaluation of options.

Table 1

Comparison of Cooling Water Alternatives

Plant Performance Summary	**Wet Cooling**	**Dry Cooling**	**Wet/dry Cooling**
Net power output, MW			
summer	1,035	1,002	1,005
winter	1,085	1,040	1,037
average	1,060	1,021	1,021
Incremental	(base)	-39	-40
Total fuel consumed, 10^6 Btu/hr			
summer	6,500	6,481	6,481
winter	6,523	6,521	6,521
average	6,511	6,501	6,501
Incremental	(base)	-10	-10
Makeup water, gpm			
summer	4,665	0	2,276
winter	4,370	0	2,138
average	4,517	0	2,207
Incremental	(base)	-4,517	-2,310
Blowdown discharge, gpm	226	0	110
Incremental	(base)	-226	-116
Cost Summary ($ millions or $millions/yr)			
Cooling system ROM capital cost	38	58	51
Incremental	(base)	20	13
Cooling water chemicals	0.9	0	0.6
Incremental annualized costs			
Cooling system capital recovery		1.9	1.2
Fuel		-0.2	-0.2
Makeup water		-0.2	-0.1
Cooling water chemicals		-0.9	-0.5
Lost electricity generation		7.2	7.3
Incremental annual cost		7.8	7.8

Basis

Plant capacity factor	0.6
Simple capital recovery	
Term, yrs	20
Rate	7.0%
Capital recy factor	0.0944
Fuel cost, $/10^6 Btu	3.00
Water cost, $/100 cu ft	0.125
Incremental power, $/MW-hr	35.00

CLIENT: MOUNTAINVIEW POWER COMPANY
PROJECT: 1116 MW POWER PLANT
LOCATION: SAN BERNARDINO, CA.
CASE: WET

FLUOR DANIEL, INC.
CONTRACT 04-414021
BY: EW
DATE: 13-Jul-00
RUN DATE: 10-July-2000

COOLING OPTIONS
MECHANICAL DRAFT COOLING TOWER – WET SYSTEM
CAPACITY: 2 TOWERS X 120,729 GPM
ESTIMATING METHOD: IN-HOUSE PRICING & CAP ADJ BULKS FROM MLP (-30% TO +30% ESTIMATE)

A/C No.	Description	QUANTITY TOTAL	UNIT	PROD MULT	CHART MH'S	JOBSITE MH's	WAGE RATE $	TOTAL COSTS - INST JAN. 2000 LABOR $	SUB-CONTRACT $	MATERIAL $	TOTAL $
00	PILES	350	EA	1.25					568,800		568,800
00	EXCAVATION / BACKFILL	18,180	CY	1.25	2,800	3,500	$23.34	81,700		22,000	103,700
10	PUMP PITS & SKID FDNS	830	CY	1.25	4,150	5,190	$24.24	125,800		158,500	284,300
10	COOLING TOWER BASINS	4,200	CY	1.25	29,820	37,280	$24.24	903,700		714,000	1,617,700
20	C.T. PIT STEEL	40	TON	1.25	1,000	1,250	$24.24	30,300		60,000	90,300
40	COOLING TOWERS (2 X 120,729 GPM)	2	EA	1.25					5,000,000		5,000,000
40	SURF CONDENSER (STEAM TURB, 130000SF EA)	2	EA	1.25	10,000	12,500	$26.17	327,100		3,740,000	4,067,100
40	CCW HEAT EXCHANGER	4	EA	1.25	400	500	$26.17	13,100		208,000	221,100
40	CIRCULATING CW PUMPS	6	EA	1.25	1,200	1,500	$26.17	39,300		1,872,000	1,911,300
40	AUXILIARY CW PUMPS	4	EA	1.25	300	380	$26.17	9,900		270,400	280,300
40	CT MAKEUP PUMPS	2	EA	1.25	130	160	$26.17	4,200		37,400	41,600
40	CLOSED LOOP CW PUMPS	4	EA	1.25	460	580	$26.17	15,200		228,800	244,000
40	CHEMICAL INJECTION SKIDS	1	EA	1.25	300	380	$26.17	9,900		118,000	127,900
40	C.T. FIRE PROTECTION	1	EA				$26.17		267,500		267,500
40	SIDESTREAM SOFTENER/CLARIFIER SYSTEM	1	EA				$26.17		850,000		850,000
40	HOISTS - C.T. SCREENS (5-TON MANUAL EA)	2	EA	1.25	200	250	$26.17	6,500		31,200	37,700
50	PIPING - CWS/CWR, MU, BD	12,430	LF	1.25	34,520	43,150	$25.97	1,120,600		1,172,500	2,293,100
60	ELECTRICAL PDC & AUX XFMR – EQUIP & BULKS	1	EA	1.25	14,170	17,710	$25.61	453,600		1,417,100	1,870,700
83	PAINT (PIPE)						$25.97		157,000		157,000
	SCAFFOLDING			1.25	8,350	10,440	$25.54	266,600			266,600
	ADDERS							85,200			85,200
	EXTENDED WORK WEEK, CASUAL O.T. @ 2%	15.63%						546,000			546,000
	TOTAL DIRECT FIELD COSTS				107,800	134,770	$29.97	4,038,700	6,843,300	10,048,900	20,931,900
91	TEMP CONSTR FACILITIES										
92	CONSTR SVCS, SUPPLIES, EXP										
93	FLD STAFF, SUBS & EXP										
94	PAYROLL B & B & INSURANCE										
95	CONSTRUCTION EQUIPMENT										
90	SMALL TOOLS										
99	FIELD OVERHEAD COSTS										
	INDIRECT FIELD COSTS	166%	X DFL								6,704,000
	COMMISSIONING	1.26%	X (DFC • IFC)								$348,000
	TOTAL FIELD COST										27,983,900
91	FLD SUPPORT & CONSTRUCTION										
92	H.O. CONSTRUCTION SUPPORT										
93	PROJECT MANAGEMENT										
95	ENGINEERING & DESIGN										
96	PROCUREMENT										
97	H.O. EXPENSES										
98-9	H.O. PAYROLL & B & B										
99-9	H.O. OVERHEAD COSTS										
	TOTAL HOME OFFICE COSTS	15.00%	X TFC (LESS COOLING WATER EQUIPMENT TURNKEY COSTS)								3,280,000
	TOTAL FIELD & OFFICE COSTS										31,263,900
	SALES TAX	7.75%	X TOTAL DIR FLD MATERIAL + 60% S/C + 10% IFC								1,149,000
	ESCALATION	6.00%	X TFOC +SALES TAX								1,945,000
	CONTINGENCY	4.80%	X TFOC + SALES TAX + ESCALATION								1,649,000
	WARRANTY (ALLOWANCE OR %)	0.1276%	X TFOC + SALES TAX+ ESCALATION + CONTINGENCY								46,000
	FEE	6.00%	X TFOC + ESCALATION + CONTINGENCY								2,163,000
	TOTAL PROJECT COSTS										38,215,900
										Round to:	38,000,000
							"Checked:		"Approved:		

NOTES:

(1)

CLIENT:	MOUNTAINVIEW POWER COMPANY
PROJECT:	1116 MW POWER PLANT
LOCATION:	SAN BERNARDINO, CA.
CASE:	DRY

FLUOR DANIEL, INC.
CONTRAC 04-414021
BY: EW
DATE: 13-Jul-00
RUN DATE 25-Jan-2000

COOLING OPTIONS
AIR COOLED CONDENSERS – DRY SYSTEM
CAPACITY: 2 CONDENSERS X 1168.3 KPPH STEAM COND
ESTIMATING METHOD: IN-HOUSE PRICING & CAP ADJ BULKS FROM MLP (-30% TO +30% ESTIMATE)

A/C No.	Description	QUANTITY TOTAL	UNIT	PROD MULT	CHART MH'S	JOBSITE MH's	WAGE RATE $	TOTAL COSTS - INST JAN, 2000 LABOR $	SUB-CONTRACT $	MATERIAL $	TOTAL $
00	PILES	240	EA	1.25					390,000		390,000
00	EXCAVATION & BACKFILL (FDNS)	623	CY	1.25	140	180	$23.34	4,200			4,200
10	AIR COOLER FOUNDATIONS	136	CY	1.25	3,210	4,010	$24.24	97,200		23,700	120,900
10	PIPE SUPPORT FOUNDATIONS	3	CY	1.25	80	100	$24.24	2,400		600	3,000
20	PIPE SUPPORTS – TEE SUPPORTS	4	TON	1.25	80	100	$25.04	2,500		4,900	7,400
40	AIR COOLED SURFACE CONDENSERS	2	EA	1.25			$26.17		40,000,000		40,000,000
40	AUXILIARY AIR COOLERS	4	EA	1.25			$26.17		857,000		857,000
40	STG, HRSG, BFW & COND PUMPS PRICE DELTA FROM BASE CASE						$26.17		3,300,000	##########	511,000
50	PIPING ERECTION	1	LOT	1.25	200	250	$25.97	6,500			6,500
60	ELECTRICAL PDC & AUX XFMR – EQUIP & BULKS	1	EA	1.25	12,470	15,590	$25.61	399,300		1,577,100	1,976,400
	SCAFFOLDING			1.25	1,360	1,700	$25.54	43,400			43,400
	ADDERS							13,900			13,900
	EXTENDED WORK WEEK, CASUAL O.T. @ 2%	15.63%						89,000			89,000
	TOTAL DIRECT FIELD COSTS				17,540	21,930	$30.02	658,400	44,547,000	##########	44,022,700
91	TEMP CONSTR FACILITIES										
92	CONSTR SVCS, SUPPLIES, EXP										
93	FLD STAFF, SUBS & EXP										
94	PAYROLL B & B & INSURANCE										
95	CONSTRUCTION EQUIPMENT										
90	SMALL TOOLS										
99	FIELD OVERHEAD COSTS										
	INDIRECT FIELD COSTS	166%	X DFL								1,093,000
	COMMISSIONING	1.26%	X (DFC + IFC)								$568,000
	TOTAL FIELD COST										45,683,700
91	FLD SUPPORT & CONSTRUCTION										
92	H.O. CONSTRUCTION SUPPORT										
93	PROJECT MANAGEMENT										
95	ENGINEERING & DESIGN										
96	PROCUREMENT										
97	H.O. EXPENSES										
98-9	H.O. PAYROLL & B & B										
99-9	H.O. OVERHEAD COSTS										
	TOTAL HOME OFFICE COSTS	25.00%	X TFC (LESS AIR COOLED EXCHANGERS TURNKEY COSTS)								1,207,000
	TOTAL FIELD & OFFICE COSTS										46,880,700
	SALES TAX	7.75%	X TOTAL DIR FLD MATERIAL + 60% S/C + 10% IFC								1,988,000
	ESCALATION	6.00%	X TFOC +SALES TAX								2,933,000
	CONTINGENCY	4.80%	X TFOC + SALES TAX + ESCALATION								2,487,000
	WARRANTY (ALLOWANCE OR %)	#######	X TFOC + SALES TAX+ ESCALATION + CONTINGENCY								69,000
	FEE	6.00%	X TFOC + ESCALATION + CONTINGENCY								3,262,000
	TOTAL PROJECT COSTS										57,629,700
										Round to:	58,000,000

CLIENT: MOUNTAINVIEW POWER COMPANY
PROJECT: 1116 MW POWER PLANT
LOCATION: SAN BERNARDINO, CA.
CASE: WET- DRY

FLUOR DANIEL, INC.
CONTRACT 04-414021
BY: EW
DATE: 13-Jul-00
RUN DATE: 10-July-2000

COOLING OPTIONS
MECHANICAL DRAFT COOLING TOWERS & A/C CONDENSERS– WET-DRY SYSTEM
CAPACITY: 2 TOWERS X 49,950 GPM & 2 X A/C CONDSRS
ESTIMATING METHOD: IN-HOUSE PRICING & CAP ADJ BULKS FROM MLP (-30% TO +30% ESTIMATE)

A/C No.	Description	QUANTITY TOTAL	UNIT	PROD MULT	CHART MH'S	JOBSITE MH's	WAGE RATE $	TOTAL COSTS - INST JAN, 2000 LABOR	SUB-CONTRACT	MATERIAL	TOTAL
								$	$	$	$
00	PILES	300	EA	1.25					487,500		487,500
00	EXCAVATION / BACKFILL	71,609	CY	1.25	11,218	14,020	$23.34	327,200		22,000	349,200
10	PUMP PITS & SKID FDNS	580	CY	1.25	2,910	3,640	$24.24	88,200		110,800	199,000
10	COOLING TOWER BASINS	2,520	CY	1.25	17,890	22,360	$24.24	542,000		428,400	970,400
10	AIR COOLER FOUNDATIONS	68	CY	1.25	1,610	2,010	$24.24	48,700		11,900	60,600
10	AIR COOLER PIPE SUPPORT FOUNDATIONS	2	CY	1.25	60	80	$24.24	1,900		400	2,300
20	C.T. PIT STEEL	28	TON	1.25	700	880	$24.24	21,300		42,000	63,300
40	AIR COOLED SURFACE CONDENSERS	2	EA	1.25			$26.17		17,500,000		17,500,000
40	AUXILIARY AIR COOLERS		EA	1.25			$26.17				0
40	COOLING TOWERS (2 X 49950 GPM)	2	EA	1.25					2,000,000		2,000,000
40	SURF CONDENSER (STEAM TURB, 50000SF EA)	2	EA	1.25	6,000	7,500	$26.17	196,300		1,760,000	1,956,300
40	CCW HEAT EXCHANGER	4	EA	1.25	400	500	$26.17	13,100		208,000	221,100
40	CIRCULATING CW PUMPS	4	EA	1.25	560	700	$26.17	18,300		1,169,000	1,187,300
40	AUXILIARY CW PUMPS	4	EA	1.25	180	230	$26.17	6,000		270,400	276,400
40	CT MAKEUP PUMPS	2	EA	1.25	80	100	$26.17	2,600		37,400	40,000
40	CLOSED LOOP CW PUMPS	4	EA	1.25	390	490	$26.17	12,800		257,900	270,700
40	CHEMICAL INJECTION SKIDS	1	EA	1.25	200	250	$26.17	6,500		70,800	77,300
40	C.T. FIRE PROTECTION	1	EA				$26.17		840,000		840,000
40	SIDESTREAM SOFTENER/CLARIFIER SYSTEM	1	EA				$26.17		510,000		510,000
40	HOISTS - C.T. SCREENS (5-TON MANUAL EA)	1	EA	1.25	50	60	$26.17	1,600		5,200	6,800
40	STG, HRSG, BFW & COND PUMPS PRICE DELTA FROM BASE CASE						$26.17		3,300,000	(3,089,000)	211,000
50	PIPING - CWS/CWR, MU, BD	7,460	LF	1.25	20,710	25,890	$25.97	672,400		703,500	1,375,900
60	ELECTRICAL PDC & AUX XFMR – EQUIP & BULKS	1	EA	1.25	18,340	22,930	$25.61	587,200		2,049,300	2,636,500
83	PAINT (PIPE)						$25.97		94,200		94,200
	SCAFFOLDING			1.25	6,830	8,540	$25.54	218,100			218,100
	ADDERS							69,100			69,100
	EXTENDED WORK WEEK, CASUAL O.T. @ 2%	15.63%						443,000			443,000
	TOTAL DIRECT FIELD COSTS				88,128	110,180	$29.74	3,276,300	24,731,700	4,058,000	32,066,000
91	TEMP CONSTR FACILITIES										
92	CONSTR SVCS, SUPPLIES, EXP										
93	FLD STAFF, SUBS & EXP										
94	PAYROLL B & B & INSURANCE										
95	CONSTRUCTION EQUIPMENT										
90	SMALL TOOLS										
99	FIELD OVERHEAD COSTS										
	INDIRECT FIELD COSTS	166%	X DFL								5,439,000
	COMMISSIONING	1.26%	X (DFC + IFC)								$473,000
	TOTAL FIELD COST										37,978,000
91	FLD SUPPORT & CONSTRUCTION										
92	H.O. CONSTRUCTION SUPPORT										
93	PROJECT MANAGEMENT										
95	ENGINEERING & DESIGN										
96	PROCUREMENT										
97	H.O. EXPENSES										
98-9	H.O. PAYROLL & B & B										
99-9	H.O. OVERHEAD COSTS										
	TOTAL HOME OFFICE COSTS	20.00%	X TFC (LESS A/C CONDSR & COOLING WATER EQUIPMENT TURNKEY COSTS)								3,426,000
	TOTAL FIELD & OFFICE COSTS										41,404,000
	SALES TAX	7.75%	X TOTAL DIR FLD MATERIAL + 60% S/C + 10% IFC								1,507,000
	ESCALATION	6.00%	X TFOC +SALES TAX								2,575,000
	CONTINGENCY	4.80%	X TFOC + SALES TAX + ESCALATION								2,183,000
	WARRANTY (ALLOWANCE OR %)	0.1276%	X TFOC + SALES TAX+ ESCALATION + CONTINGENCY								61,000
	FEE	6.00%	X TFOC + ESCALATION + CONTINGENCY								2,864,000
	TOTAL PROJECT COSTS										50,594,000
										Round to:	51,000,000

Client:	Mountainview Power Company, LLC	Contract:	04414021
Location:	San Bernardino County, CA	Revision:	A
Project:	Mountainview Power Project	Date:	13-Jul-2000 02:08 PM
Equipment:	4-GE 7FA's, 2-GE Reheat STG	By:	C. Stacklin Chk/Appr'd CS / FA

DUKE/FLUOR DANIEL™

TABLE 2

RESPONSE TO CEC DR 68 AND 69 (00-AFC-2)

C:\DATA\Projects\04414021 Mountainview\Mountainview Project Data Request Rev A (12 Jul 00) .xls]Co

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1	Cooling System		Wet Cooling						Dry Cooling						Wet / Dry Cooling					
2	Ambient Temperature	°F	82			30			82			30			82			30		
3	Relative Humidity	%	34			60			34			60			34			60		
4	HRSG Duct Burner Status		On	Off	Off	Off	Off	Off	On	Off	Off	Off	Off	Off	On	Off	Off	Off	Off	Off
5	Evaporative Cooler Status		On	Off	Off	Off	Off	Off	On	Off	Off	Off	Off	Off	On	Off	Off	Off	Off	Off
6	GTG Load	%	100	75	50	100	75	50	100	75	50	100	75	50	100	75	50	100	75	50
7	STG Exhaust Pressure (calculated)	inHgA	2.20	1.68	1.41	1.04	0.95	0.95	4.65	3.39	2.75	2.00	2.00	2.00	4.65	3.39	2.75	2.00	2.00	2.00
8	STG Exhaust Steam Flow Rate (calculated)	lb/h	1,163 500	872 600	895 300	1 042 000	924 100	733 800	1 168 300	877 100	699 200	1,051 400	832 500	740 700	1 168 300	877 100	699 200	1 051 400	832 500	740 700
9	Estimated Performance																			
10	GTG Gross Power Output (Each)	kW	150 950	113 875	78 320	177 907	135 035	90 565	150 661	113 767	76 261	177 750	134 850	90 543	150 661	113 767	76 261	177 750	134 850	90 543
11	STG Gross Power Output	kW	211 731	156 194	120 020	186 800	168 813	132 932	188 930	147 206	113 221	176 005	159 281	125 350	188 930	147 206	113 221	176 005	159 281	125 350
12	Gross Power Output (Units 3 & 4)	kW	1 063 262	767 888	545 320	1 085 424	877 766	628 204	1 036 584	749 480	531 486	1 063 010	858 362	612 872	1 036 584	749 480	531 486	1 063 010	858 362	612 872
13	Total Auxiliary Power (Units 3 & 4)	kW	27 867	25 400	23 507	27 938	25 085	18 756	34 450	31 480	29 274	22 560	19 980	17 044	32 007	29 447	27 477	26 240	23 537	19 395
14	Net Power Output	kW	1 035 395	742 488	521 813	1 057 486	852 681	608 449	1 002 134	718 000	502 212	1 040 450	838 373	595 826	1 004 577	720 033	504 009	1 036 770	834 825	593 477
15	GTG Fuel Gas Consumption, LHV (Units 3 & 4)		6 013 676	4 738 484	3 596 528	6 522 512	5 397 212	4 087 532	6 009 768	4 737 608	3 596 544	6 520 608	5 398 636	4 087 888	6 009 768	4 737 608	3 596 544	6 520 608	5 398 636	4 087 888
16	Duct Burner Fuel Gas Consumption, LHV (Units 3 & 4)		486 372	0	0	0	0	0	471 564	0	0	0	0	0	471 564	0	0	0	0	0
17	Total Fuel Gas Consumption, LHV (Units 3 & 4)	kBtu/h	6 500 048	4 738 484	3 596 528	6 522 512	5 397 212	4 087 532	6 481 332	4 737 608	3 596 544	6 520 608	5 398 636	4 087 888	6 481 332	4 737 608	3 596 544	6 520 608	5 398 636	4 087 888
18	Net Heat Rate	Btu/kWh	6 278	6 382	6 892	6 168	6 330	6 718	6 468	6 598	7 161	6 267	6 437	6 861	6 452	6 580	7 136	6 289	6 464	6 888
19	Estimated CT Makeup Water, Chemical and Fuel Costs																			
20	Plant (Average) Capacity Factor		0.60						0.60						0.60					
21	Operating Hours per Year	h/y	5 256						5 256						5 256					
22	Fuel Gas Consumption, HHV	mm Btu/y	37 580 679	27 398 018	20 793 686	37 710 555	31 204 521	23 632 475	37 472 471	27 390 954	20 793 778	37 698 547	31 201 191	23 634 533	37 472 471	27 390 954	20 793 778	37 698 547	31 201 191	23 634 533
23	Fuel Gas Price, HHV	US$/mmBtu	3.000						3.000						3.000					
24	Fuel Gas Cost	mm US$/y	112 742	82 188	62 381	113 132	93 614	70 897	112 417	82 173	62 381	113 098	93 604	70 904	112 417	82 173	62 381	113 098	93 604	70 904
25	CT Makeup Water Usage (Units 3 & 4)	USgpm	4 665	3 574	2 692	4 370	3 895	3 125	0	0	0	0	0	0	2 276	1 726	1 379	2 138	1 891	1 500
26	CT Makeup Water Usage (Units 3 & 4)	acre-ft/y	4 515	3 462	2 790	4 229	3 770	3 025	0	0	0	0	0	0	2 203	1 670	1 334	2 069	1 830	1 452
27	CT Makeup Water Usage (Units 3 & 4)	mm ft³/y	197	151	122	184	164	132	0	0	0	0	0	0	96	73	58	90	80	6
28	CT Makeup Water & Treatment Cost ($0.125)	US$/100 ft³	0.125						0						0.125					
29	CT Makeup Water & Treatment Cost	mm US$/y	0.246	0.189	0.152	0.230	0.205	0.165	0.000	0.000	0.000	0.000	0.000	0.000	0.120	0.091	0.073	0.113	0.100	0.079
30	Chemicals Cost	mm US$/y	1.2						0						0.61					
31	Total CT Makeup Water, Chemical and Fuel Cost	mm US$/y	114 188	83 577	63 733	114 562	95 019	72 262	112 417	82 173	62 381	113 098	93 604	70 904	113 147	82 874	63 064	113 821	94 313	71 581
32	Average Electricity Sales Price	$/MWH	35.00						35.00						35.00					
33	Lost Generation	mm US$/y	—	—	—	—	—	—	6 118	4 505	3 606	3 134	2 632	2 322	5 689	4 131	3 275	3 811	3 265	2 754
34	Air Cooled Condenser (one of two condensers)																			
35	Steam Flow Rate	lb/h	—	—	—	—	—	—	1,168 300	877 100	699 200	1 051 400	832 500	740,700	584 150	438 550	349 600	525 700	486 250	370 350
36	Total Fan Power	kW	—	—	—	—	—	—	6 040	5 944	5 886	911	587	260	3 121	3 071	3 041	470	303	134
37	Plot Length x Width / Height	ft	—						380 x 200 / 108						172 x 213 / 95					
38	Number of Cells		—						45						20					
39	Fan Diameter	ft	—						32						32					
40	Noise Level (Near Field @ 3 ft / Far Field @ 400 ft)	dBA	—						65 / 65						65 / 62					
41	Estimated Delivered and Erected Cost	US$	—						20 000 000						8 750 000					
42	Surface Condenser (one of two condensers)																			
43	Steam Flow Rate	lb/h	1 163 500	872 600	895 300	1 042 000	924 100	733 800	—	—	—	—	—	—	584 150	438 550	349 600	525 700	486 250	370 350
44	Circulating Water Flow Rate	USgpm	116 265	117 621	119 006	116 326	109 273	81 899	—	—	—	—	—	—	77 156	78 092	58 998	46 764	70 385	62 58[illegible]
45	Size - HI Surface	ft²	145 174						—						72 587					
46	Estimated Cost	US$	1 870 000						—						880 000					
47	Cooling Tower (one of two towers)																			
48	Makeup Water	USgpm	2 332	1 789	1 446	2 185	1 948	1 563	—	—	—	—	—	—	1 138	863	689	1 069	945	75[illegible]
49	Blowdown at 25 Cycles of Concentration	USgpm	93	72	58	87	78	63	—	—	—	—	—	—	46	35	28	43	38	3[illegible]
50	Total Fan Power	kW	1 671	1 656	1 646	1 585	1 301	576	—	—	—	—	—	—	836	828	823	782	651	28[illegible]
51	Drift Rate @ 0.0005%	USgpm	0.7						—						0.4					
52	Plot Length x Width / Height	ft	54 x 384 / 41						—						43 x 169 / 41					
53	Number of Cells		10						—						5					
54	Fan Diameter	ft	28						—						28					
55	Noise Level (Near Field @ 3 ft / Far Field @ 50 ft)	dBA	85 / 78						—						85 / 78					
56	Estimated Delivered and Erected Cost	US$	2 500 000						—						1 000 000					
57	Cooling System ROM Installed Cost Estimate[1]	US$	38 000 000						58 000 000						51 000 000					
58	Annual Amortized Payments Over 20 Years[2]	US$	—						1 660 717						1 209 468					

59 Notes: 1. Cooling system ROM installed cost estimate does not include cost of financing.

60 2. Annual amortized payments are additional payments for wet and wet dry cooling systems, using the wet system as a baseline. Interest is estimated at 7%.

61

Process Design Basis and Assumptions Pertaining to CEC DR 68 and 69 (00-AFC-2)

The wet cooling cases are presented in columns 1 through 6 of Table 2. Column 1 at ambient conditions of 82 ° F and 34% relative humidity represents the summer average performance at both the gas turbine generator load at 100% and the peak load due to duct firing and evaporative cooling. Columns 2 and 3 are at the same ambient conditions with no duct firing and no evaporative cooling at 75% and 50% gas turbine generator loads, respectively.

Columns 4, 5 and 6 are at ambient conditions of 30 ° F and 60% relative humidity with no duct firing and no evaporative cooling and represent the gas turbine generator loads at 100%, 75% and 50%, respectively. Dry cooling cases are in columns 7 through 12 and wet / dry cooling cases are in columns 13 through 18.

The Estimated Performance section of Table 2 shows the power output and fuel consumption for the requested energy balances. Data is calculated using Thermoflow / GTPro library data versus supplier's information. Wet / dry cooling is based on conditions established for dry cooling, e.g., the back pressure on the steam turbine generator is set by the air cooled condenser. The only difference is that half of the steam turbine generator exhaust steam is routed to the cooling tower and the balance to the air cooled condenser. Therefore, Thermoflow cycle runs are not necessary. Equipment sizing and cycle performance were adjusted to account for the differences in wet / dry cooling.

Operating costs associated with the three options are in the estimated cooling tower makeup water, chemical and fuel costs. Lost generation represents the annual revenue loss based on the difference in net power output (versus wet cooling). Fuel gas price, cooling tower makeup water and treatment cost and average electricity sales prices are in-house estimates. The cost for water is assumed to be \$0.125 per 100 ft^3 considering the potential for reclaimed water usage. Cooling tower makeup water is determined on the basis of 20 to 25 cycles of concentration. Drift is at 0.0006%. Labor, maintenance, energy, spare and renewal parts, materials and waste are not included.

Equipment estimated performance and sizing information for the Air Cooled Condenser, the Surface Condenser and Cooling Tower are based on one of two items, since the plant consists of two units. Sizes are estimated using supplier information from similar projects.

United States Environmental Protection Agency
Office of Water (4303)
EPA-821-R-01-036
November 2001

EPA

Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities

- ***Construction materials***: Towers can be made from concrete, steel, wood, and/or fiberglass.

Generally, all cooling towers with plume abatement features are hybrid towers. According to the Standard Handbook of Power Plant Design, attempts to modify towers with special designs and construction features to abate plumes has been tested but not accepted as an effective technology. Natural draft towers are concrete towers, although some old natural draft wood cooling towers do exist. Therefore, for costing purposes, concrete is assumed to be the material used for building natural draft cooling towers.

Capital Cost of Cooling Towers

Typically, the cost of the project is determined based on the following factors: type of equipment to be cooled (e.g., coal fired equipment, natural gas powered equipment); location of the water intake (on a river, lake, or seashore); amount of power to-be-generated (e.g., 50 Megawatt vs. 200 Megawatt); and volume of water needed. The volume of water needed for cooling depends on the following critical parameters: water temperature, make of equipment to be used (e.g, G.E turbine vs. ABB turbine, turbine with heat recovery system and turbine without heat recovery system), discharge permit limits, water quality (particularly for wet cooling towers), and type of wet cooling tower (i.e., whether it is a natural draft or a mechanical draft).

Two cooling tower industry managers with extensive experience in selling and installing cooling towers to power plants and other industries provided information on how they estimate budget capital costs associated with a wet cooling tower. The rule of thumb they use is $30/gpm for a delta of 10 degrees and $50/gpm for a delta of 5 degrees.[7] This cost is for a "small" tower (flow less than 10,000 gpm) and equipment associated with the "basic" tower, and does not include installation. Ancillary costs are included in the installation factor estimate listed below. Above 10,000 gpm, to account for economy of scale, the unit cost was lowered by $5/gpm over the flow range up to 204,000 gpm. For flows greater than 204,000 gpm, a facility may need to use multiple towers or a custom design. Combining this with the variability in cost among various cooling tower types, costs for various tower types and features were calculated for the flows used in calculating screen capacities at 1 ft/sec and 0.5 ft/sec.

To estimate costs specifically for installing and operating a particular cooling tower, important factors include:

- ***Condenser heat load and wet bulb temperature (or approach to wet bulb temperature)***: Largely determine the size needed. Size is also affected by climate conditions.

- ***Plant fuel type and age/efficiency***: Condenser discharge heat load per Megawatt varies greatly by plant type (nuclear thermal efficiency is about 33 percent to 35 percent, while newer oil-fired plants can have nearly 40 percent thermal efficiency, and newer coal-fired plants can have nearly 38 percent thermal efficiency).[8] Older plants typically have lower thermal efficiency than new plants.

- ***Topography***: May affect tower height and/or shape, and may increase construction costs due to subsurface conditions. For example, sites requiring significant blasting, use of piles, or a remote tower location will typically have greater installation/construction cost.

- ***Material used for tower construction***: Wood towers tend to be the least expensive, followed by fiberglass reinforced plastic, steel, and concrete. However, some industry sources claim that Redwood capital costs might be much higher compared to

[7]The delta is the difference between the cold water (tower effluent) temperature and the tower wet bulb temperature. This is also referred to as the design approach. For example, at design conditions with a delta or design approach of 5 degrees, the tower effluent and blowdown would be 5 degrees warmer than the wet bulb temperature. A smaller delta (or lower tower effluent temperature) requires a larger cooling tower and thus is more expensive.

[8]With a 33 percent efficiency, one-third of the heat is converted to electric energy and two-thirds goes to waste heat in the cooling water.

Table 2-19. Total Annual O&M Cost Equations - 1st scenario for Redwood Towers with Environmental Mitigation Features[1]

Type of Tower	O&M Cost Equations[2]	Correlation Coefficient
Non-Fouling Film Fill tower	$y = -4E\text{-}06x^2 + 11.163x + 2053.7$	$R^2 = 0.9999$
Noise reduction (10dBA)	$y = -5E\text{-}06x^2 + 12.235x + 2512.5$	$R^2 = 0.9999$
Hybrid tower (Plume Abatement 32DBT)	$y = -1E\text{-}05x^2 + 21.36x + 5801.6$	$R^2 = 0.9998$
Splash Fill tower	$y = -4E\text{-}06x^2 + 11.163x + 2053.7$	$R^2 = 0.9999$
Dry/wet tower	$y = -1E\text{-}05x^2 + 25.385x + 7328.1$	$R^2 = 0.9998$

1) Features include non-fouling film, noise reduction, plume abatement, or splash fill
2) x is flow in gpm and y is annual O&M cost in dollars.

reduction in available energy tends to offset the gains in available energy that would result from the greater enthalpy changes due to the reduced pressure. Thus, the expansion of the steam within the turbine and the formation of condensed moisture establishes a practical lower limit for turbine exhaust pressures, reducing the efficiency advantage of even lower condenser surface temperatures particularly at higher turbine steam loading rates. As can be seen in the turbine performance curves presented below, this reduction in efficiency at lower exhaust pressures is most pronounced at higher turbine steam loading rates. This is due to the fact that higher steam loading rates will produce proportionately higher turbine exit velocities.

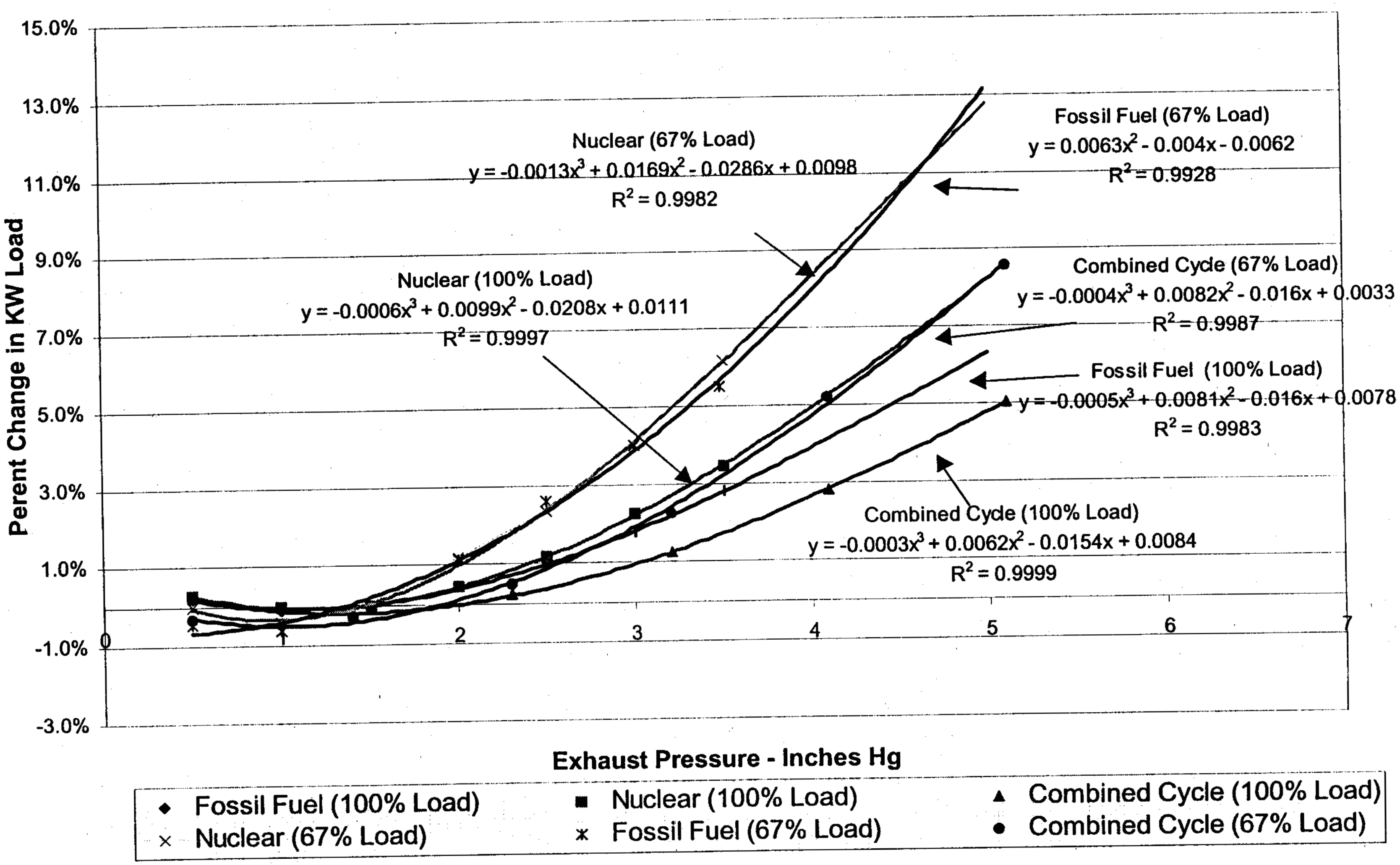
Attachment B presents several graphs showing the change in heat rate resulting from differences in the turbine exhaust pressure at a nuclear power plant, a fossil fueled power plant, and a combined-cycle power plant (steam portion). The first graph (Attachment B-1) is for a GE turbine and was submitted by the industry in support of an analysis for a nuclear power plant. The second graph (Attachment B-2) is from a steam turbine technical manual and is for a turbine operating at steam temperatures and pressures consistent with a sub-critical fossil fuel plant (2,400 psig, 1,000 °F). The third graph (Attachment B-3) is from an engineering report analyzing operational considerations and design of modifications to a cooling system for a combined-cycle power plant.

The changes in heat rate shown in the graphs can be converted to changes in turbine efficiency using Equation 1. Several curves on each graph show that the degree of the change (slope of the curve) decreases with increasing loads. Note that the amount of electricity being generated will also vary with the steam loading rates such that the more pronounced reduction in efficiency at lower steam loading rates applies to a reduced power output. The curves also indicate that, at higher steam loads, the plant efficiency optimizes at an exhaust pressure of approximately 1.5 inches Hg. At lower exhaust pressures the effect of increased steam velocities actually results in a reduction in overall efficiency. The graphs in Attachment B will serve as the basis for estimating the energy penalty for each type of facility.

Since the turbine efficiency varies with the steam loading rate, it is important to relate the steam loading rates to typical operating conditions. It is apparent from the heat rate curves in Attachment B that peak loading, particularly if the exhaust pressure is close to 1.5 inches Hg, presents the most efficient and desirable operating condition. Obviously, during peak loading periods, all turbines will be operating near the maximum steam loading rates and the energy penalty derived from the maximum loading curve would apply. It is also reasonable to assume that power plants that operate as base load facilities will operate near maximum load for a majority of the time they are operating. However, there will be times when the power plant is not operating at peak capacity. One measure of this is the capacity factor, which is the ratio of the average load on the plant over a given period to its total capacity. For example, if a 200 MW plant operates, on average, at 50 percent of capacity (producing an average of 100 MW when operating) over a year, then its capacity factor would be 50 percent.

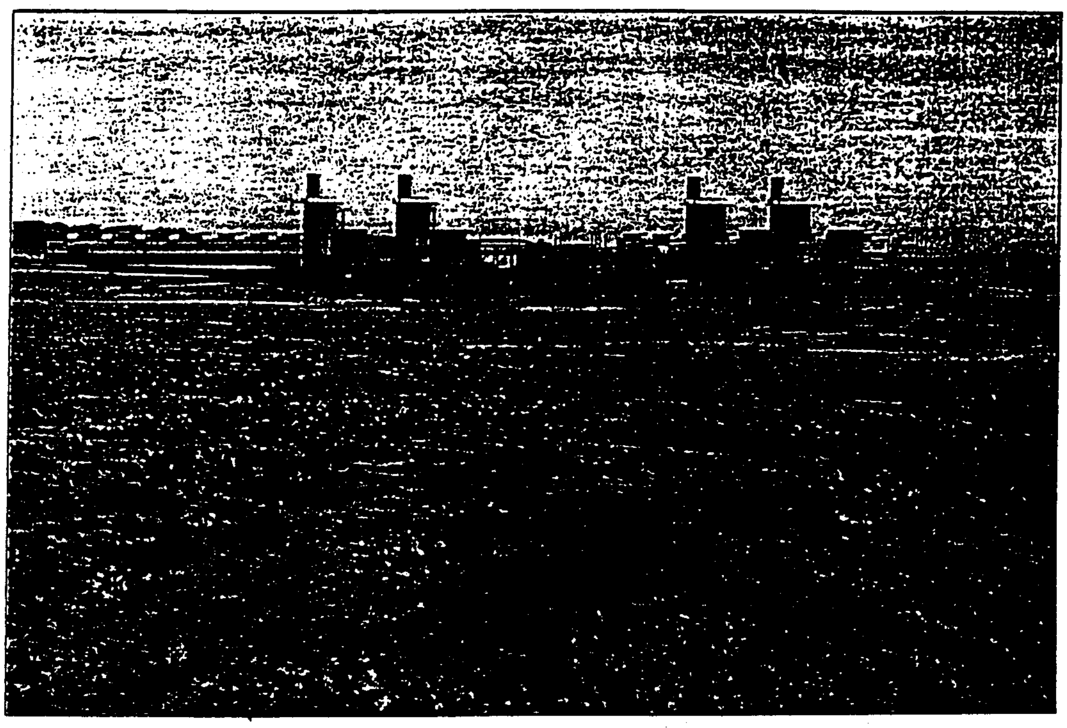
The average capacity factor for nuclear power plants in the U.S. has been improving steadily and recently has been reported to be approximately 89 percent. This suggests that for nuclear power plants, the majority appear to be operating near capacity most of the time. Therefore, use of the energy penalty factors derived from the maximum load curves for nuclear power plants is reasonably valid. In 1998, utility coal plants operated at an average capacity of 69 percent (DOE 2000). Therefore, use of the energy penalty values derived from the 67 percent load curves would appear to be more appropriate for fossil-fuel plants. Capacity factors for combined-cycle plants tend to be lower than coal-fired plants and use of the energy penalty values derived from the 67 percent load curves rather than the 100 percent load curves would be appropriate.

Figure 1
Plot of Various Turbine Exhaust Pressure Correction Curves for 100% and 67% Steam Loads



APPLICATION FOR A CLASS I PERMIT FOR THE LA PAZ GENERATING FACILITY LA PAZ COUNTY, ARIZONA

October 2, 2001



Submitted by:
Allegheny Energy Supply
La Paz Generating Facility L.L.C.
McDowell Road Professional Plaza
14122 West McDowell Road, Suite 201
Goodyear, Arizona 85338

Submitted to:
Arizona Department of Environmental Quality
3303 North Central Avenue
Phoenix, Arizona 85012

APPLIED ENVIRONMENTAL CONSULTANTS, INC.

Owner Allegheny
Plant La Paz Combined
Project No. 97183.00
Title Heat Balance R

By Kevin Chiu
August 13, 2001

Case Description	ALLEGHENY ENERGY LA PAZ PROJECT BLACK & VEATCH PROJECT # 097183.0040					ALLEGHENY ENERGY LA PAZ PROJECT BLACK & VEATCH PROJECT # 097183.0040					ALLEGHENY ENERGY LA PAZ PROJECT BLACK & VEATCH PROJECT # 097183.0040	
	Hot Temperature / Base Load / Unfired	Hot Temperature / Base Load / Fired	Hot Temperature / 85% Load	Hot Temperature / 70% Load	Average Temperature / Base Load / Unfired	Average Temperature / Base Load / Fired	Average Temperature / 85% Load	Average Temperature / 70% Load	Cold Temperature / Base Load / Unfired	Cold Temperature / Base Load / Fired	Cold Temperature / 85% Load	Cold Temperature / 70% Load
	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off	Steam Injection Off
	Evaporative Cooler On	Evaporative Cooler On	Evaporative Cooler Off	Evaporative Cooler Off	Evaporative Cooler On	Evaporative Cooler On	Evaporative Cooler Off	Evaporative Cooler Off	Evaporative Cooler Off	Evaporative Cooler Off	Evaporative Cooler Off	Evaporative Cooler Off
	Supplemental Firing Off	Supplemental Firing On	Supplemental Firing Off	Supplemental Firing Off	Supplemental Firing Off	Supplemental Firing On	Supplemental Firing Off	Supplemental Firing Off	Supplemental Firing Off	Supplemental Firing On	Supplemental Firing Off	Supplemental Firing Off
Case #	Case_1	Case_2	Case_3	Case_4	Case_5	Case_6	Case_7	Case_8	Case_9	Case_10	Case_11	Case_12
Ambient Temperature	115 F	115 F	115 F	115 F	72 F	72 F	72 F	72 F	20 F	20 F	20 F	20 F
Number of CTG/HRSG Units Operating	2	2	2	2	2	2	2	2	2	2	2	2
CTG Model	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2	SW501FD2
CTG Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load Level (percent of base load)	100.00%	100.00%	85.00%	70.00%	100.00%	100.00%	85.00%	70.00%	100.00%	100.00%	85.00%	70.00%
STG Output	172.8 MW	242.8 MW	141.3 MW	129.1 MW	180.2 MW	246.8 MW	150.4 MW	136.4 MW	187.2 MW	249.1 MW	154.5 MW	138.4 MW
STG Throttle Conditions, psia/F	1575P/1050T	2280P/1050T	1313P/1038T	1214P/1040T	1609P/1050T	2280P/1050T	1350P/1008T	1238P/1017T	1845P/1036T	2280P/1050T	1354P/977T	1228P/984T
STG Hot Reheat Conditions, psia/F	337P/1050T	480P/1050T	278P/1034T	256P/1037T	343P/1050T	479P/1050T	291P/1008T	264P/1014T	354P/1035T	477P/1050T	290P/975T	267P/981T
Condenser Pressure	2.31 in HgA	2.87 in HgA	2.07 in HgA	1.87 in HgA	1.73 in HgA	2.18 in HgA	1.51 in HgA	1.43 in HgA	1.22 in HgA	1.52 in HgA	1 in HgA	1 in HgA
New & Clean Performance per Block												
Number of CTG/HRSG Units Operating	2	2	2	2	2	2	2	2	2	2	2	2
Gross CTG Output, kW (each)	162,870	162,870	120,880	100,720	174,330	174,330	142,650	118,520	192,950	192,950	164,320	135,490
Gross CTG Output, kW (total)	325,740	325,740	241,760	201,440	348,660	348,660	285,300	237,040	385,900	385,900	328,640	270,980
Gross CTG Heat Rate, Btu/kWh (LHV)	9,225.4	9,225.4	9,833.3	10,360.5	9,078.1	9,078.1	9,365.7	9,780.5	8,917.0	8,917.0	9,058.5	9,457.2
Gross CTG Heat Rate, Btu/kWh (HHV)	10,240.2	10,240.2	10,921.4	11,507.0	10,083.8	10,083.8	10,402.0	10,862.6	9,903.7	9,903.7	10,060.8	10,503.7
CTG Heat Input, MBtu/h (LHV) (total)	3,005.1	3,005.1	2,377.3	2,087.0	3,165.6	3,165.6	2,672.0	2,318.4	3,441.1	3,441.1	2,976.9	2,562.5
CTG Heat Input, MBtu/h (HHV) (total)	3,337.6	3,337.6	2,640.4	2,318.0	3,516.0	3,515.8	2,967.7	2,574.8	3,821.8	3,821.8	3,306.4	2,846.1
Duct Burner Heat Input, MBtu/h (LHV) (each)	0.0	276.2	0.0	0.0	0.0	262.2	0.0	0.0	0.0	239.2	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV) (each)	0.0	306.6	0.0	0.0	0.0	291.2	0.0	0.0	0.0	265.7	0.0	0.0
Duct Burner Heat Input, MBtu/h (LHV) (total)	0.0	552.4	0.0	0.0	0.0	524.4	0.0	0.0	0.0	478.4	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV) (total)	0.0	613.3	0.0	0.0	0.0	582.5	0.0	0.0	0.0	531.4	0.0	0.0
Gross STG Output, kW	172,860	242,880	141,260	129,080	180,170	246,630	150,370	136,410	187,210	249,100	154,540	138,410
STG Output, percent of CTG Output	53.07%	74.56%	58.43%	64.08%	51.67%	70.74%	52.71%	57.55%	48.51%	64.55%	47.02%	51.08%
Gross Plant Output, kW	498,600	568,620	383,020	330,520	528,830	595,290	435,670	373,450	573,110	635,000	483,180	409,390
Gross Cycle Heat Rate, Btu/kWh (LHV)	6,027	6,256	6,207	6,314	5,986	6,199	6,133	6,208	6,004	6,172	6,161	6,260
Gross Cycle Heat Rate, Btu/kWh (HHV)	6,694	6,949	6,894	7,013	6,649	6,885	6,812	6,895	6,669	6,855	6,843	6,952
Auxiliary Power/Losses, kW	13,780	16,450	13,150	12,780	14,180	16,600	13,490	13,050	14,450	16,810	11,770	11,270
Auxiliary Power/Losses, percent of gross	2.76%	2.89%	3.43%	3.87%	2.68%	2.79%	3.09%	3.49%	2.52%	2.65%	2.44%	2.75%
Block Heat Input, MBtu/h (LHV)	3,005.1	3,557.6	2,377.3	2,087.0	3,165.6	3,690.0	2,672.0	2,318.4	3,441.1	3,919.5	2,976.9	2,562.5
Block Heat Input, MBtu/h (HHV)	3,337.6	3,951.1	2,640.4	2,318.0	3,516.0	4,098.3	2,967.7	2,574.8	3,821.8	4,353.2	3,306.4	2,846.1
Net Block Output, kW	484,820	552,170	369,870	317,740	514,650	578,690	422,180	360,400	558,660	618,190	471,410	398,120
Net Block Heat Rate, Btu/kWh (LHV)	6,201	6,443	6,427	6,568	6,151	6,376	6,329	6,433	6,160	6,340	6,315	6,437
Net Block Heat Rate, Btu/kWh (HHV)	6,887	7,156	7,139	7,295	6,831	7,082	7,029	7,145	6,841	7,042	7,014	7,149
Net Block Efficiency (LHV)	55.03%	52.96%	53.09%	51.95%	55.47%	53.51%	53.91%	53.04%	55.40%	53.82%	54.03%	53.01%
Net Block Efficiency (HHV)	49.54%	47.68%	47.80%	46.77%	49.95%	48.18%	48.54%	47.76%	49.88%	48.48%	48.65%	47.73%

Notes

1 The combustion turbine generator (CTG) performance is estimated based on SW data.
2 The CTG fuel was assumed to have 0.3 grains of sulfur per 100 SCF and a higher heating value of 23,883 Btu/lb
3 A desuperheating condenser has been assumed.
4 Cycle makeup water temperature is assumed to be 59°F.
5 HRSG designed unfired to annual ambient average conditions of 58°F, 85%RH.
6 Maximum steam turbine throttle pressure is assumed to be 2280 psia based on the heat balance for a Siemens KN steam turbine.
7 This performance is an estimate which does not contain any commercial margins and can not be guaranteed.
8 Revision 3 revised for the elevation from 408 ft to 1344 ft.