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February 21, 2013

Ms. Mary Jo Kunkle
Michigan Public Service Commission
6545 Mercantile Way
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case N$^{o.}$ U-17087

Dear Ms. Kunkle:

The following is attached for paperless electronic filing:

Direct Testimony of J. Richard Hornby on Behalf of the Michigan Environmental Council and the Natural Resources Defense Council

Exhibits MEC-5 through MEC-23

E-Service List

NOTE: Due to the size of the exhibits, this testimony and exhibits will be served and filed in multiple transmissions.

Sincerely,

Christopher M. Bzdok
chris@envlaw.com

xc: Parties to Case No. U-17087
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STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and other relief.	Case N$^{o.}$ U-17087 ALJ Mark E. Cummins

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DIRECT TESTIMONY OF J. RICHARD HORNBY
ON BEHALF OF THE MICHIGAN ENVIRONMENTAL COUNCIL
AND THE NATURAL RESOURCES DEFENSE COUNCIL

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February 21, 2013

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is J. Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues. Its primary focus is on electricity resource planning and regulation including computer modeling, service reliability, resource portfolios, financial and economic risks, transmission planning, renewable energy portfolio standards, energy efficiency, and ratemaking. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, and environmental groups, U.S. Environmental Protection Agency, Department of Energy, Department of Justice, Federal Trade Commission and National Association of Regulatory Utility Commissioners. Synapse has over twenty professional staff with extensive experience in the electricity industry.

II. BACKGROUND

Q. Please summarize your educational background.

A. I have a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now the School of Engineering at Dalhousie University, and a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT).

Q. Please summarize your work experience.

A. I have over thirty years of experience in the energy industry, primarily in utility regulation and energy policy. Since 1986, as a regulatory consultant I have provided expert testimony and litigation support on natural gas and electric utility resource planning, cost allocation and rate design issues in over 120 proceedings in the United States and Canada. During that period my clients have included utility regulators, consumer advocates, environmental groups, energy marketers, gas producers, and utilities. Prior to 1986 I served as Assistant Deputy Minister of Energy for Nova Scotia where I helped prepare the province's first comprehensive energy plan and served on a federal-provincial board responsible for regulating exploration and development of offshore oil and gas reserves.

I was the lead author of reports projecting long-term avoided energy supply costs in New England prepared in 2007, 2009 and 2011. I was co-author of Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers, a 2006 report prepared for the National Association of Regulatory Utility Commissioners (NARUC). In the past five years I have testified in several electric resource planning cases in Arkansas and Kentucky, and I am currently engaged in two cases in West Virginia.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Michigan Environmental Council ("MEC") and the Natural Resources Defense Council ("NRDC").

Q. Have you testified previously before the Michigan Public Service Commission (Commission)?

A. Yes. In 1991 and 1992 I submitted testimony in gas cost recovery plan cases of the Michigan Gas Company (U-9752) and Consumers Power Company (U-10030) respectively. In 2006 I submitted testimony in the 2005 PSCR plan reconciliation case of Consumer Energy Company (U-14474-R) regarding its implementation of the Resource Conservation Plan ("RCP") for the Midland Cogeneration Venture Limited Partnership ("MCV") facility. I also submitted testimony in Case No. U-14992 regarding the proposal by Consumer Energy Company to sell its Palisades plant and enter a Power Purchase Agreement (PPA) with the buyer, Entergy.

III. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The MEC and NRDC retained Synapse to assist in their review of the application by Consumers Energy Company ("Consumers Energy" or "Company") for a rate increase to finance, among other things, approximately $1.5 billion in capital spending between 2011 and 2014 on projects for its generating plants (Exhibit A-29 revised). Over three quarters of that $1.5 billion is for capital investments at the Company's five largest coal units. Those units, which the Company refers to as "The Big Five", are DE Karn units 1 and 2, JH Campbell units 1 and 2 and the Company's share of JH Campbell unit 3. The aggregate installed capacity of these five units is 1,900 MW. The capital expenditures on these units referred to in Exhibit A-29 is the initial portion of the Company's projected total capital expenditure through 2020 of approximately $ 1.4 billion on the Big Five units in order to enable them to comply with various environmental regulations, and thereby continue operating through at least 2030.

The purpose of my testimony is to provide an overview of our analysis of whether it is reasonable for the Company to invest in these environmental compliance measures at each of the Big Five units, i.e. to "retrofit" the units, rather than retiring any of them. My testimony discusses the resource options Consumers Energy evaluated, the range of future scenarios it used to evaluate those resource options, its projection of revenue requirements for each resource option under those future scenarios and its conclusions regarding the merits of its proposed capital expenditures based upon its projections and analyses.

Synapse witness Wilson describes her review of the Company's use of *Strategist*, a computer model, to calculate the incremental revenue requirements of two of its three resource strategies, i.e., retrofit all Big Five units and retire all Big Five units and replace them with a mix of purchases and gas new capacity. The Company made this calculation based on its projections of load, operating costs and market prices over a twenty-nine year evaluation period, 2012 to 2040. She also describes her use of Strategist to calculate the incremental revenue requirements of a more limited strategy under which the Company retires only one or two of the Big Five Units. Finally she describes her calculation of the incremental revenue requirements of retiring Campbell units 1 and 2 using a different set of projections for natural gas prices and carbon emission allowance costs over the 2012 to 2040 period.

Q. What data sources did you rely upon to prepare your review of the Company's request?

A. My review relies primarily upon the direct testimonies and Exhibits of Company witnesses Ronk, Popa and Kehoe and their responses to various data requests. In addition I reviewed projections of natural gas prices and carbon allowance costs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit MEC-5 - Resume of James Richard Hornby
- Exhibit MEC-6 - Capacity and Annual Generation, Continued Operation Scenario, 2012 - 2040
- Exhibit MEC-7 - Environmental Compliance Capital Costs, Big Five Units
- Exhibit MEC-8 - Exhibit A-1, Case No. U-16054

- Exhibit MEC-9 - Binz, Ronald J. *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*. CERES. April 2012.
- Exhibit MEC-10 - Economics of Big 5 Coal Plant Operation Beyond 2015
- Exhibit MEC-11 - 17087-MEC-CE-78(l)
- Exhibit MEC-12 - Scram Exhibit CRS-1 20110601_Kentucky Utilities
- Exhibit MEC-13 - 17087-MEC-CE-84
- Exhibit MEC-14 - Tierney, Susan. *Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During Interesting Times*. Analysis Group. September 2009.
- Exhibit MEC-15 - AEO 2012 forecast
- Exhibit MEC-16 - Projections of Henry Hub Gas Prices (nominal $/MMBtu), 2012 - 2020
- Exhibit MEC-17 - 2012 Synapse report
- Exhibit MEC-18 - Projections of Carbon Dioxide Allowance Costs (nominal $/short ton), 2012 – 2040
- Exhibit MEC-19 - 17087-MEC-CE-88, and Attachment 1
- Exhibit MEC-20 - 17087-MEC-CE-54
- Exhibit MEC-21 - 17087-MEC-CE-60
- Exhibit MEC-22 - 17087-MEC-CE-82b
- Exhibit MEC-23 - 17087-MEC-CE-318

IV. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize the Company's proposal to install environmental control equipment on its Big Five Units.

A. Consumers Energy is proposing to install environmental control equipment and measures at each of its Big Five units. The Company estimates the aggregate capital cost of those investments to be $1.4 billion through 2020. Mr. Ronk maintains that installing this equipment at each of the Big Five Units is reasonable based upon the results of an economic evaluation which calculates the revenue requirements for three possible resource strategies, i.e., retrofit all Big Five Units, retire all Big Five Units and replace their capacity entirely with purchased capacity, and retire all Big Five Units and replace their capacity entirely with a mix of purchased capacity plus new gas capacity. According to Mr. Ronk's analysis the strategy of retrofitting all Big Five Units, which his analysis refers to as Continued Operation, has a lower net present value revenue requirement ('NPVRR") than the two replacement strategies he evaluated under his "Base Case" scenario as well as under five sensitivity cases.

Q. Please summarize your major findings, conclusion, and recommendation regarding the Company's proposal.

A. My conclusion is that the Company's proposal is not reasonable based upon the following findings. First, the Company did not evaluate potential resource strategies consisting of retiring one or more of the Big Five units and retrofitting the remaining units. For example, using the Company's assumptions, our analysis indicates that a strategy under which the Company retires Campbell unit 2 would have a minimally higher NPVRR, but it would have a lower financial risk to ratepayers. As I discuss in my testimony, by retiring Campbell unit 2 the Company would avoid the possibility of incurring higher than projected costs to comply with National Ambient Air Quality Standards ("NAAQS"), the Clean Water Act, and possible future regulation of carbon emissions.

Second, the Company did not evaluate its potential resource strategies under future scenarios in which compliance costs are much higher than it has projected. Specifically, the costs for Campbell Units 1 and 2 to comply with sulfur dioxide ("SO2") reductions under the new 1-hour NAAQS rule would be higher than the Company has projected if it ultimately has to install Spray Dry Absorber (SDA) technology to control SO2 emissions at those two units rather than the lower capital cost Dry Sorbent Injection ("DSI") technology the Company is assuming. Further, the Company's cost of compliance with Section 316(b) of the Clean Water Act would be higher at any unit that ultimately has to install a closed-cycle cooling tower in addition to the lower cost control measures the Company is assuming.

Third, the Company did not evaluate the economics of retrofitting each individual unit, or a combination of units, using a reasonable and up-to-date projection of natural gas prices. Based upon an Energy Information Agency (EIA) Reference Case projection of gas prices from Annual Energy Outlook (AEO) 2012, which is consistent with the August 2012 forecast upon which the Company based its decision to build the new Thetford gas combined cycle unit, our analysis indicates that individual unit retirement strategies under which the Company retires either Campbell unit 1, Campbell unit 2, Karn unit 1 or Karn unit 2 would have a lower NPVRR than its Continued Operation strategy. Both the 2012 AEO forecast and Consumer Energy's August 2012 forecast were issued before the Company filed the application at issue here, yet the Company used a December 2011 forecast with higher projected gas prices in this application.

Fourth, the Company did not test the sensitivity of its potential resource strategies to a higher projection of carbon emission allowance costs over the 2012 to 2040 period. Our analysis indicates that individual unit retirement strategies under which the Company retires either Campbell unit 1, Campbell unit 2, Karn unit 1 or Karn unit 2 would again have a lower NPVRR relative to the Continued Operation strategy under a future based on the AEO 2012 gas price forecast and a reasonable, low end forecast of carbon regulation compliance costs beginning 2020.

Based upon those findings, and my conclusion, I recommend that the Commission not approve the Company's request for rate relief to fund its proposed capital expenditures for environmental control measures at Campbell units 1 and 2. I further recommend that the Commission not approve the Company's request for rate relief to fund its proposed capital expenditures for environmental control measures at Karn units 1 and 2 until the Company submits updated economic evaluations for each unit. The updated evaluations should include a case based upon an up-to-date reasonable projection of natural gas prices and the Company compliance cost assumptions, a second case which considers a reasonable projection of carbon allowance costs, a third case which assumes each unit will require a cooling tower to comply with Section 316(b), and a fourth case which assumes both a reasonable projection of carbon costs and a cooling tower.

V. REVIEW OF CONSUMERS ENERGY PROPOSAL TO RETROFIT THE BIG FIVE UNITS

Q. Please place the role of the Big Five units into context by summarizing the Company's projected mix of capacity and energy under its Continued Operation strategy.

A. Under its Continued Operation strategy the Company is projecting that the Big Five units will account for approximately 23 percent of its capacity and 34 percent of its annual energy in 2015 and similar percentages through 2030. The Company's projected mix of capacity and energy over the entire period 2012 to 2040 under its Continued Operation strategy, as modeled in Strategist, is illustrated on pages 1 and 2 of Exhibit MEC-6. That Exhibit indicates that the Company is projecting to acquire the balance of its capacity and energy from a mix of nuclear, natural gas, oil and purchases.

Q. Please summarize the Company's assessment of the known and emerging environmental regulations its existing coal units are facing and the cost of complying with those regulations.

A. Company witness Popa states that the Company's coal units are facing the following known and emerging environmental regulations:

- Clean Air Interstate Rule (CAIR)/Cross-State Air Pollution Rule (CSAPR);
- National Ambient Air Quality Standards (NAAQS);
- Mercury and Air Toxics Standard (MATS);
- Michigan Mercury Rule (MMR);
- Clean Water Act, Section 316(b);
- Steam Electric Effluent Guidelines (SEEG); and
- Resource Conservation and Recovery Act (RCRA)

The cost of complying with RCRA is site or plant specific rather than unit specific, in other words the RCRA compliance costs do not vary materially with the operation of the individual units at each plant. The other compliance costs can be assigned, or allocated, to individual units.

According to the estimates Ms. Popa presented in her Supplemental Testimony, the Company expects to invest a total of $1.4 billion in order to enable all Big Five units to comply with those regulations. In addition, certain of the compliance measures will reduce the capacity available from the units and will also increase their variable operating and maintenance (O&M) costs.

Q. Is the Company projecting that some units will be more expensive to retrofit than others?

A. Yes. According to the Company the average capital cost to retrofit all five units, when expressed on a capital cost per unit of capacity basis, is $ 783 /kW. However, the comparable capital cost to retrofit Campbell unit 2 is $1,320 /kW, over fifty percent higher than the average. Table 1 summarizes the capital cost for each unit, as well as the plant site specific capital costs. The detailed costs from Ms. Popa's Supplemental testimony that underlay these values are presented on page 1 of Exhibit MEC-7.

Table 1 Capital Costs of Environmental Control Measures at Big Five

Plant / Unit	Total Capital Cost (Nom$, '000)	De-rated Capacity (MW)	Capital cost / kW
Karn Unit 1	**$ 197,674**	**253**	**$ 781**
Karn Unit 2	**$ 160,764**	**258**	**$ 623**
Campbell Unit 1	**$ 181,128**	**254**	**$ 713**
Campbell Unit 2	**$ 327,697**	**248**	**$ 1,320**
Campbell Unit 3	**$ 574,133**	**827**	**$ 694**
Sub-total	***$ 1,441,396***	***1,841***	***$ 783***
KARN RCRA	***$ 1,759***		
Campbell RCRA	***$ 3,828***		
TOTAL	***$ 1,446,983***	***1,841***	***$ 786***

One of the reasons why the capital cost per kW to retrofit Campbell unit 2 is so much higher is that the Company is projecting the compliance measures to de-rate its capacity by about one-third, from 355 MW to 248 MW.

Q. Is there a risk that the capital costs of retrofitting the Big Five units could be higher than the Company has projected?

A. Yes. There are at least two circumstances under which the capital costs of retrofitting the Big Five units could be higher than the Company has projected.

First, the Company is assuming that Campbell units 1 and 2 will be able to comply with the MATS rule by installing DSI technology at those two units. DSI is a lower capital cost measure than the SDA technology the Company had previously considered for those units. However, DSI is less effective than SDA at reducing sulfur dioxide (SO2), which the Company's testing at Campbell unit 1 appears to bear out.[1] Thus DSI technology may not adequate to enable those two units to meet their obligations for SO2 emission reductions under the new 1-hour SO2 NAAQS and/or a CSAPR replacement rule. If the DSI technology turns out to be incapable of achieving the needed SO2 reductions, the Company would have to install additional SO2 controls, thereby incurring additional capital costs to continue operating these units.

[1] I reviewed the testing as discovery response 17087-MEC-CE-385. However, I am not sponsoring the response as an exhibit because the Company has designated it confidential.

Second, there is a risk that the Company's costs of complying with Section 316(b) of the Clean Water Act could be higher than the Company has projected. The Company is hoping that the tests of various control technologies it plans to conduct starting in mid-2013 will enable it to ultimately demonstrate to the Environmental Protection Agency (EPA) that it does not require closed-cycle cooling towers (Popa Direct, page 23). However, if the results from the Company's anticipated four to five years of testing do not enable it to ultimately make that demonstration, and the Company ultimately has to install closed-cycle cooling towers at all five units, the estimated cost of complying with that regulation could increase its total compliance costs by up to $470 million, or one-third as shown on page 2 of Exhibit MEC-7.[2] Those 316(b) compliance costs would increase the total capital cost at Campbell 2 to $ 1,520 /kW and the capital costa per kW of the other four units to a range from $751/kW to $1,064/kW.

Q. Please contrast the age and capital costs of retrofitting each of the Big Five units with the capital cost of a new gas-fired combustion turbine (CT) or a new gas-fired combined cycle unit (CC).

A. Based on Exhibit MEC-8 (Exhibit A-1, Case U-16054), four of the Big Five units range in age from 46 years (Campbell unit 2) to 54 years (Karn unit 1).[3] The

[2] Synapse calculation based upon *Closed-Cycle Retrofit Study*, response 17087-MEC-CE-318, which I am sponsoring as Exhibit MEC-23.

[3] The exception is Campbell unit 3, at 33 years.

Company is proposing to retrofit each of those four units to enable them to continue operating from 2015 to 2030, approximately 15 years. By 2030 the four units will range in age from 63 years to 71 years. In contrast, the Company projects a new CC, which would have an expected book life of at least 30 years, would have an installed cost in the order of $1,000 to $1,200 per kW, less than its estimate for Campbell unit 2. Similarly, the Company estimates that a new CT, which has an expected life of at least 20 years, would have an installed cost in the order of $781/kW, which is the same range as the Company's estimates for Karn units 1 & 2 and Campbell unit 1.

Given the similarity in the capital costs of retrofits and of new gas capacity, the question for the economic evaluation is primarily whether the variable cost of electricity generated from each of the retrofitted Big Five units through 2030 will be significantly less than the variable cost of electricity generated from a new gas CC or of electricity purchases through 2030. The answer to that question will be driven largely by the Company's assumptions and projections regarding coal prices, natural gas prices, and carbon allowance prices through 2030.

Q. Please summarize the economic evaluation the Company conducted to evaluate its potential resource strategies for complying with the environmental requirements facing the Big Five units.

A. According to Mr. Ronk, and as summarized in his Exhibit A-50, the Company evaluated the strategies available for complying with these environmental requirements in three major steps.

First, the Company identified three possible resource strategies for complying with these environmental requirements. The three resource strategies, presented in Mr. Ronk's Exhibit A-50, are essentially:

- 100 percent retrofit of the Big Five, which Exhibit A-50 labels as the Continued Operation scenario;
- 100 percent retirement of the Big Five and replacement with 100 percent purchases, which Exhibit A-50 labels as the "Early Retirements scenario" plus "Purchase Capacity needs All Years"; and
- 100 percent retirement of the Big Five and replacement with a mix of purchases and new gas CC, which Exhibit A-50 labels as the "Early Retirements scenario" plus "1000 MW Max Purchases, Optimized with New Gas".

Second, the Company developed a projected Base Case for the period 2012 through 2040 to calculate the NPVRR of each strategy under its projection of the future market conditions in which each of the three resource strategies would be operating. It also identified six variations on that Base Case to test the sensitivity of the NPVRR of each strategy to future market conditions different from the Base

Case, for example futures in which replacement capacity was available at costs lower than those in its Base Case.

Third, the Company developed projections of the revenue requirements associated with each resource strategy over the 29 year evaluation period, 2012 to 2040, under the Base Case and each of the six sensitivity scenarios. The Company developed those projections using the Strategist model, a computer simulation model

Based upon his review of the revenue requirements of each resource strategy under the Base Case and each of the six sensitivity cases, summarized in his Exhibit (A-50) and four points he makes on pages 17 and 18 of his direct testimony, Mr. Ronk concludes that retrofitting all Big Five units is reasonable. His additional four points are that:

- It is prudent to maintain a diversity of supply and technology;
- The removal of the five generating units from service is likely to adversely affect the cost of providing a stable transmission system;
- The addition of gas fueled generation to replace the capacity and energy is likely to increase the cost of the existing gas transmission system and;
- The un-depreciated book value associated with the five generating units is significant.

Q. Please describe the approach the Synapse team used to determine if the Company's proposal were reasonable and cost-effective for complying with the environmental requirements the Company is facing.

A. The Synapse team has reviewed the Company's application in an appropriate level of detail for a base rate filing, based on guidance provided in the Commission's final order in Case U-16794. Specifically we attempted to review the validity of the key input assumptions underlying the Company's projection of revenue requirements for each resource strategy under its base case, as well as to determine if the Company had evaluated the full range of resource strategies available to it.

Q. What are the key steps in assessing the reasonableness of the Company's proposal in this case?

A. First, parties must verify the Company's support for assumptions for a period of 29 years. Second, parties must review the mathematical accuracy of its calculation of revenue requirements for each of those years. Given the uncertainty associated with the values of key input assumptions over that planning horizon it is particularly important that all parties have a clear understanding of the basis for the Company's key input assumptions regarding resource costs and of the range of future market and regulatory conditions it may face. It is particularly important to "stress test" those assumptions under a range of realistic possible future scenarios. An April 2012 report by Ron Binz, former Chairman of the Colorado Public Utilities

Commission, highlights the importance of considering risk when making electricity regulation decisions.[4] This report is presented in Exhibit MEC-9.

VI. ASSESSMENT OF COMPANY PROPOSAL

Q. Please summarize the Company's projected revenue requirements for each of the resource strategies and future cases it considered.

A. The Company's projected NPVRR for each resource strategy for the Base Case and the six sensitivity cases are presented on page 1 of Exhibit MEC-10. The "Early Retirements combined with a mix of purchases and new gas capacity" is the strategy most competitive with the Continued Operation strategy. As indicated in columns (I) and (j) of Exhibit MEC-10, the NPVRR's of those two resource strategies are very close. Columns (k) 1 and (k) 2 of Exhibit MEC-10 presents the difference in NPVRR between those two resource strategies in absolute and percentage terms respectively.

The fact that the NPVRRs of the resource strategies are relatively close is not surprising, given the twenty-nine year timeframe and the inclusion of incremental costs of other resources common to each of the three resource strategies. Those common costs include the costs of the Company's nuclear, gas, and oil units as well as its purchases. However, it does require one to focus on the differences in

[4] Binz, Ronald J. *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*. CERES. April 2012. Exhibit MEC-9.

NPVRR by resource strategy for each future case, as well as to consider the financial risks associated with each strategy, in order to determine which resource option is cost-effective and reasonable.

In the balance of my testimony, I use the Company's projections for the Continued Operation strategy under its Base Case to illustrate the problems we have found with its projections.

Q. Has your team been able to confirm the validity of all key input assumptions and verify the Company's calculations and projections based upon those inputs?

A. No. Our review has found several aspects of the Company's filing unclear, particularly in terms of the key input assumptions presented in testimony and the Company's production cost modeling assumptions book and the input assumptions actually found within the Strategist model. Ms. Wilson discusses the lack of clarity and inconsistencies in various aspects of the Company filing. As a result we do not claim to have confirmed the validity of all key input assumptions underlying the Company's projection of revenue requirements for each resource strategy under each future case, or to have verified the mathematical accuracy of all of its projections.

Q. Please list the major problems the Synapse team has found with the Company's economic evaluation.

A. Our review identified problems with the following major aspects of the Company's economic evaluation:

- the limited range of resource strategies the Company modeled in Strategist;
- the projection of natural gas prices the Company used to evaluate the three resource strategies; and
- the limited range of future cases the Company modeled to "stress test" its potential resource strategies, in particular the Company did not evaluate a future case with a reasonable projection of carbon prices.

A. Limited Range of Resource Strategies

Q. Please comment on the Company's decision to limit its evaluation of strategies for retrofits and retirements of the Big Five units to three "all or nothing" strategies.

A. The Company's decision to limit its evaluation to three all or nothing retrofit and retirement strategies for the Big Five units is not reasonable.

First, they do not represent all of the major strategies available to the Company. It would certainly make sense for the Company to evaluate additional strategies that involve retiring one, or a sub-set, of the Big Five units and retrofitting the remaining units. Analyzing each unit using a "one by one" approach is particularly important for Consumers Energy given that its estimates of the capital cost of retrofitting Campbell unit 2 are so much higher on a cost per kW basis than those of the other four units. When we asked the Company why they modeled the units together instead of individually, Mr. Ronk responded that the company studied the units as an aggregate due to their similar size, age, and technologies as well as the NPV of Net System Cost of early retirement. (Discovery Response 17087-MEC-CE-78(l), attached as Exhibit MEC-11).

This answer is hard to reconcile with the facts. According to pages 4 and 5 of Mr. Kehoe's direct testimony, Campbell 3 is 830 MW (770 MW owned share). Campbell 3 is therefore much larger than Campbell 1 at 260 MW, or Campbell 2 at 355 MW (and proposed to be derated to 248 MW); and it also much larger than the two Karn units at 515 MW combined. As far as age, according to Exhibit MEC-8 Campbell 3 is 33 years old, while the other units range from 46 to 54 years old. We asked Consumers Energy to explain its position that these units were similar, but the company has yet to answer. In a similar case in 2011, Case No. 2011-00161, Kentucky Utilities Company prepared an extensive set of evaluations, on a unit by unit basis, in order to determine which set of units to retrofit and which to retire. See Exhibit MEC-12, Scram Exhibit CRS-1 20110601_Kentucky Utilities.

In addition, while the Company has issued a solicitation for capacity recently, it has not issued a Request for Proposal (RFP) to buy existing gas-fired CC or CT to replace all or part of the Big Five units. (Exhibit MEC-13, discovery response 17087-MEC-CE-84.) A 2009 report by Dr. Susan Tierney, a former Assistant Secretary for Policy at the U.S. Department of Energy and Massachusetts public utility commissioner, describes the benefits of acquiring capacity and energy through an RFP process.[5] This report is presented in Exhibit MEC-14.

The Company also did not provide a formal analysis supporting its decision to limit its evaluation to those three strategies. (See Exhibit MEC-13, discovery response 17087-MEC-CE-84, declining to consider existing gas capacity or demand side management.)

Q. Has Ms. Wilson calculated the NPVRR for strategies under which Consumers Energy would retire one, or a combination of, the Big Five units?

A. Yes. Page 2 of Exhibit MEC-10 presents the NPVRR of strategies under which the Company would retire one, or a combination of, the Big Five units. Those calculations are based solely on the Company's input assumptions. This analysis indicates that a strategy under which the Company retires Campbell units 1 and 2 would have only a 0.1% higher NPVRR than the Continued Operation strategy. However, the retirement strategy would have a lower financial risk for ratepayers. First, retiring those units would avoid the risk of higher than projected costs for Campbell units 1 and 2 to comply with the National Ambient Air Quality Standards ("NAAQS") and the Clean Water Act, as I discussed earlier. Second, as I discuss below, it would avoid the risk of higher than projected production costs at Campbell

[5] Tierney, Susan. *Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During Interesting Times*. Analysis Group. September 2009. Exhibit MEC-14.

units 1 and 2 that would result under carbon emission regulations with higher compliance costs than the Company has assumed in its Base Case.

B. Natural Gas Prices Forecast

Q. Please summarize the forecast of natural gas prices the Company used to evaluate its potential resource strategies.

A. The Company evaluated its potential resource strategies using a forecast of annual prices for natural gas delivered to its existing and potential gas-fired units in Michigan. The forecast, which the Company prepared in December 2011, consists of two components, prices at the Henry Hub and adders or basis between the Henry Hub and each of its gas-fired units. The Henry Hub is a major gas trading point located in Louisiana and is widely used as a reference point. The price of gas at the Henry Hub is the dominant component of the Company's forecasts of gas prices at its gas-fired units in Michigan.

Q. Does the forecast of natural gas prices underlying the Company's evaluations reflect the most up-to-date long-term outlook for Henry Hub prices of either the Company or the EIA?

A. No. The forecast of natural gas prices underlying the Company's evaluations is not a reasonable projection of gas prices through 2040 because it did not reflect the most up-to-date outlook of the Company or of the EIA even at the time this application was filed, much less today.

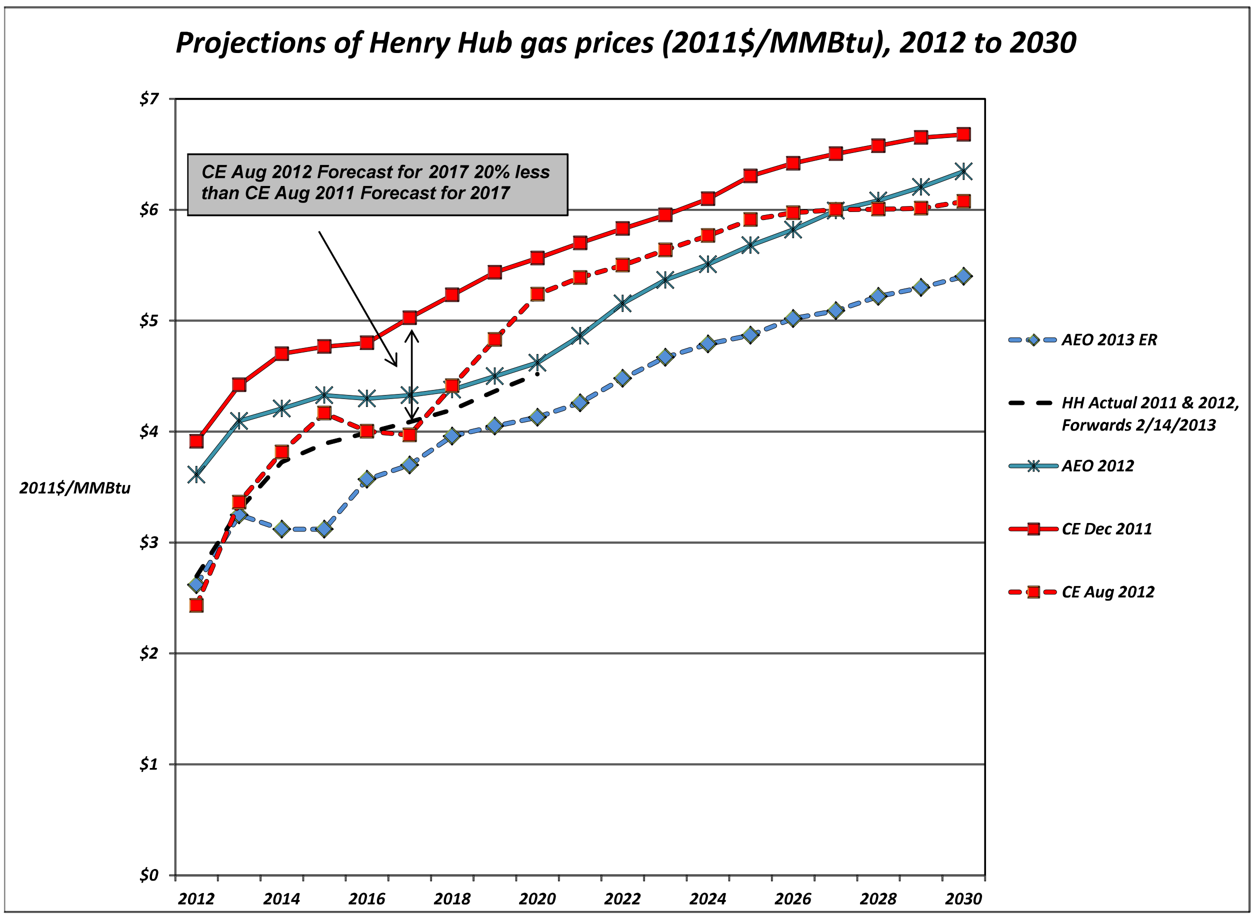
The Company developed the forecast of Henry Hub gas prices used in its evaluations in December 2011. At best that forecast reflects the Company's expectations regarding those prices at that point in time. The Company's forecast from December 2011 is higher than EIA reference case forecasts made in that timeframe. The EIA reference case forecasts were presented in AEO 2011, released in the Spring of 2011, and AEO 2012, which was released June 25, 2012, which was nearly three months before the Company filed the present application.[6] Page 1 of Exhibit MEC-15 provides a chart comparing those three forecasts.

However the Company, like many in the gas industry, has revised its long-term expectations for Henry Hub prices downward since December 2011. The Company developed a new forecast of Henry Hub prices as of August 2012, which it used to evaluate the economics of investing in the new Thetford gas CC unit. The Company's August 2012 is up to twenty-percent lower than its December 2011 forecast in certain years between 2015 and 2020, and is 10 percent lower on average over the 2015 to 2030 period most relevant to its evaluations of the economics of the Big Five units. The EIA has also reduced its expectations regarding the long-term price of natural gas substantially relative to its AEO 2011 Reference Case forecast.

The bottom line is that the Company's evaluations are based upon a December 2011 forecast of Henry Hub prices which is at least 10 percent higher

[6] I am sponsoring the AEO 2012 forecast as Exhibit MEC-15.

than its August 2012 forecast, substantially higher than current Henry Hub futures prices, and substantially higher than the reference case forecast in AEO 2013 Early Release ("ER"), the most recent EIA forecast. Figure 1, from page 2 of Exhibit MEC-15, provides a chart comparing the Company's December 2011 forecast to its August 2012 forecast and these more recent actual Henry Hub prices and forecasts. This chart plots the Company's August 2012 forecast using a dashed line with blocks and the AEO 2013 forecast using a dashed line with diamonds.



Q. Are you surprised that the Company submitted this filing in September 2012 and did not use, or refer to, its August 2012 gas price forecast?

A. Yes. Given how much lower the Company's August 2012 projection is than its December 2011 forecast, and the sensitivity of its economic evaluations to natural gas price projections, I am surprised the Company did not use its August 2012 projections as the basis for the evaluations it filed with its September 2012 application in this proceeding.

Q. Which forecast of Henry Hub prices did your team use to re-run the Company's evaluations?

A. I asked Ms. Wilson to re-run her analyses using the AEO 2012 reference case forecast. The EIA released that forecast on June 25, 2012, and thus the gas and electric industries have had ample time to review its underlying assumptions in detail. At this point I consider it to be a reasonable, conservative estimate. In particular it is higher than the AEO 2013 ER forecast, whose full set of underlying assumptions are not yet public. In addition, we did not receive the Company's August 2012 forecast until February 18, which did not allow us sufficient time to complete new modeling runs prior to our February 21 filing date. However, as indicated on page 2 of Exhibit MEC-15, the AEO 2012 forecast is generally consistent with the Company's August 2012 forecast for the years 2015 to 2030, the time period most critical to this evaluation.

Q. Did you make any other adjustments to the Company's forecast of gas prices delivered to its gas units?

A. Yes. As noted earlier, the forecast of delivered prices equals the forecast Henry Hub price plus an adder or basis differential. The Company's assumptions for those adders, as documented in its Production Cost Model ("PCM") assumptions book seemed reasonable. However, Ms. Wilson found that the adders implicit in the delivered prices for gas to new gas CT and CC units the Company actually used in its Strategist modeling were higher than those in its PCM assumptions book. Therefore we developed estimated delivered prices to new gas CT and CC units based on our revised forecast of Henry Hub prices and the percentage adders from the Company PCM assumptions book. Our forecasts of those delivered prices are provided on page 3 of Exhibit MEC-10.

Q. Did using this updated forecast of Henry Hub gas prices in your re-runs lead to a different set of results?

A. Yes. With this lower projection of natural gas prices ratepayers are better off, as compared to the Continued Operation strategy, under strategies in which the Company retires any of the Karn 1 and 2 or Campbell 1 and 2 units individually. It is even better off if it retires Campbell units 1 and 2 as a pair, or Karn units 1 and 2 as a pair. Page 2 of Exhibit MEC-10 presents the NPVRR of each of those strategies.

These NPVRR results also reflect Ms. Wilson's removal of the accelerated recovery of existing fixed costs at Big Five units that the Company assumes the Commission would allow if those units are retired. Ms. Wilson discusses that adjustment in her testimony. She advises me that the results of her runs would be essentially the same if she did not remove the accelerated recovery of those existing fixed costs.

C. Evaluation of Risk

Q. Please comment on the extent to which the Company has tested the sensitivity of its potential resource strategies to possible changes in future conditions and differences in key input assumptions.

A. The Company tested the sensitivity of its potential resource strategies to several possible changes in future conditions. However the Company did not test the sensitivity of those strategies to three major possible differences in input assumptions: specifically, higher costs to comply with Section 316(b) of the Clean Water Act, a reasonable, low-end projection of carbon prices, and the potential for higher compliance costs related to the 1-hour SO_2 NAAQS

Q. Do you have a recommendation for a more comprehensive set of sensitivities?

A. Yes. I recommend that the Company test the sensitivity of its three strategies, as well as additional individual unit retirement strategies to higher costs to comply with Section 316(b) of the Clean Water Act and a reasonable, low-end projection of carbon prices. I have discussed the potential for higher costs to comply with Section 316(b) of the Clean Water Act earlier in my testimony. In this section I will discuss the potential for high carbon allowance costs.

Q. Does the Company include a projection of carbon prices in its Base Case?

A. Yes. The Company has a projection of carbon prices beginning in 2021. This projection was prepared by CERA, a consulting firm.

Q. Why is it important for the Company to test the sensitivity of its resource strategies to carbon prices higher than those projected in its Base Case?

A. The Company projection of carbon prices is at the extreme low end of the range of carbon price projections of other utilities that Synapse has reviewed. The 2012 Synapse report describing those reviews and providing its projections is provided in Exhibit MEC-17.

I have used a chart from that report to compare the Company's Base Case projection of carbon prices to the range of forecasts from more than 25 other utilities. That comparison, which is presented in Exhibit MEC-18, also plots the low, mid and high projections from the Synapse 2012 report.

As Exhibit MEC-18 demonstrates, the mid case forecast from the Synapse 2012 report is within the range of the forecasts from the utilities covered in its review. In contrast, the Consumers energy forecast is among the lowest of the utility forecasts.

Q. How does Synapse define its low, mid, and high case forecasts?

A. As explained in the report, the Synapse low case "represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly" or with significant safety valve and offset provisions, or relies heavily on complementary policies that reduce emissions through non-price measures. The mid case assumes "a federal cap-and-trade program is implemented with significant but reasonably achievable goals," likely with complementary policies providing flexibility in meeting the goals. The high case assumes one or more factors that raise prices, including "somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets," more international pressure, or higher baseline emissions.

Q. What carbon price projection scenarios did your team use to re-run the Company's evaluations?

A. I asked Ms. Wilson to re-run her analyses using the Synapse low case forecast as a reasonable, conservative estimate.

Q. Has Ms. Wilson tested the sensitivity of resource strategies under which Consumers Energy would retire one, or a combination of, the Big Five units, using your projection of carbon allowance prices in addition to your proposed gas prices?

A. Yes. Page 2 of Exhibit MEC-10 presents the NPVRR of strategies under which the Company would retire one, or a combination of, the Big Five units for a case using my proposed projections of natural gas prices and carbon allowance costs. That analysis indicates that any of the following strategies have lower NPVRR than the continued operation strategy under that set of assumptions: retirement of Campbell unit 1, Campbell unit 2, or Campbell unit 1 and 2; or retirement of Karn unit 1, Karn unit 2, or Karn unit 1 and 2.

Using the low price forecast from the Synapse 2012 report provides a conservative sensitivity analysis. The EPA, under Section 111(d) of the Clean Air Act, has the obligation to promulgate performance standards for existing sources of greenhouse gases such as the Big Five units. Thus it is possible they could place such standards into effect earlier than the Federal legislation assumed in the Synapse 2012 forecast, and could require reductions that would equate to the Synapse mid- or high-case CO2 forecasts. This is another substantial economic risk that Consumers Energy has not accounted for in its proposal to spend $1.4 billion of ratepayer funds on these units.

D. Other Factors and Issues

Q. Please address the additional points Mr. Ronk made to support his decision that the Continued Operation strategy was reasonable.

A. On pages 17 and 18 of his direct testimony, Mr. Ronk makes four additional points to support his position that retrofitting all Big Five units is reasonable.

His first point is that it is prudent to maintain a diversity of supply and technology. While this is a valid planning principle, the Company clearly needs to choose a diverse mix of supply and technology that represents a reasonable balance of cost minimization over time and financial risk minimization over time. Our analyses indicate that the Company's proposed Continued Operation strategy does not achieve that reasonable balance. Instead the Company should be pursuing a strategy that retires Campbell units 1 and 2 and considers a range of gas peaking capacity, efficiency and renewables in addition to additional gas CC.

His second point is that removal of the five generating units from service is likely to adversely affect the cost of providing a stable transmission system. My only comment here is that the Company has presented a "straw man" resource strategy by considering only 100 percent retrofit of the Big Five or 100 percent retirement. In fact, as I have discussed, the Company may not necessarily retire all 5 units. Mr. Lanzalotta will address the specific concerns that Mr. Ronk raised regarding the transmission system impacts of Big Five unit retirements.

His third point is that addition of gas fueled generation to replace the capacity and energy is likely to increase the cost of the existing gas transmission system. Again, the Company may not necessarily retire all 5 units and in any case it should have included the impacts of its replacement strategies on its existing gas transmission system. For example, the Company has obviously decided that the benefits of adding a major new gas CC unit at Thetford outweigh any increased cost to its existing gas transmission system.

Finally, Mr. Ronk states that the un-depreciated book value associated with the five generating units is significant. While recovery of the un-depreciated book value of any of the Big Five units that may be retired is a legitimate concern of the Company shareholders, that amount is a “sunk” cost which is of no relevance to the selection of the least-cost / least-risk strategy for complying with the environmental regulations the Company is facing. According to the basic principles of economics, the costs that are relevant to the selection of that least-cost strategy are the incremental, or marginal, costs that the Company will incur in the future under each possible resource strategy. The current un-depreciated book values of each Big Five unit are not incremental costs, they will be the same whether the Company retrofits the Big Five or whether it retires the Big Five.

Q. Please address the concerns Mr. Ronk has raised regarding the incremental cost of pipeline laterals for new gas capacity built at the Campbell or Karn sites.

A. Mr. Ronk discusses the incremental cost of pipeline laterals for new gas capacity built at the Campbell or Karn sites in his testimony. However, he did not include those costs as a component of the capital cost assumptions for such units that were actually entered into the Strategist model. Moreover, the Company estimates of those costs include a 50 percent contingency factor, which is very high and much greater than the contingency factor the Company assumes for its capital costs of compliance measures. (Exhibit MEC-19, discovery request 17087-MEC-CE-88, and Attachment 1.) Finally, the capacity of the lateral serving the new Thetford unit has capacity to support a second, equal size unit.

Q. Please comment on the Company's request for rate relief for costs related to mothballing the Classic 7 units.

A. The Company has requested has requested $1.952 million for engineering studies related to its mothballing the Classic 7 units, according to Exhibit A-28 and Exhibit MEC-20, discovery request 17087-MEC-CE-54. The Company has also requested $7.5 million for mothball-related capital expenditures in 2014 under the cap ex tracker, per Exhibit A-29.

However, Consumers Energy says it does not know how much energy prices would have to increase in order to make it economical to install ACQS on the 7 Classics. (Exhibit MEC-21, discovery response 17087-MEC-CE-60.) In Exhibit MEC 22 (discovery response 17087-MEC-CE-82b), the Company states that natural gas prices would have to be at least 75% higher than its gas price forecast as of October 2011 in order for it to retrofit those units and continue operating them. The October 2011 gas forecast is the forecast the Company has referred to elsewhere as its December 2011 forecast of Henry Hub prices.

Based on my review of gas price forecasts for various high cases in AEO 2012, the probability of gas prices reaching a level 75% higher than the Company's December 2011 forecast is extremely remote. As such, the Company should not spend any further amount on studies of those units but instead should simply retire them effective April 2015.

CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize the major findings from your analysis of the Company's proposal.

A. The first major finding from our analyses is that the Company did not evaluate a reasonable range of potential resource strategies for complying with environmental regulations, and did not prepare its evaluations using a reasonable and up-to-date projection of natural gas prices.

Table 2, drawn from page 3 of Exhibit MEC-10, indicates that a strategy under which the Company retires Campbell units 1 and 2 has essentially the same NPVRR as its proposed Continued Operation strategy under the Company's Base Case assumptions, and lower NPVRR's under future cases reflecting the AEO 2012 gas price forecast and the synapse 2012 report low-carbon forecast.

Table 2. Summary Results from Evaluation of Economics of Big 5 Coal Plant Operation Beyond 2015 (Nom$, million)

		Cost / (Savings) as % of Continued Operation Scenario			
		Consumers Energy Evaluations	*Synapse Evaluations*		
	Resource Strategies	*Company Base Case*	*Company Base Case*	*EIA AEO 2012 Reference Case Henry Hub Gas price projection*	*Synapse 2012 Low Case Carbon Cost Forecast + EIA AEO 2012 Reference Case Gas price*
1	*Continued Operation Strategy*				
2	*Early Retirements + Purchase Capacity Needs All Years*	*5.37%*	*N/a*	*N/a*	*N/a*
3	*Early Retirements + 1,000 MW Max Purchases, Optimized with New Gas*	*2.31%*	*N/a*	*N/a*	*N/a*
4	*Retire Karn 1 ; Retrofit Karn 2 and Campbell 1 to 3; 1,000 MW Max Purchases, Optimized with New Gas*	*N/a*	*1.0%*	*-0.9%*	*-1.1%*
5	*Retire Karn 2 ; Retrofit Karn 1 and Campbell 1 to 3; 1,000 MW Max Purchases, Optimized with New Gas*	*N/a*	*1.1%*	*-0.8%*	*-1.0%*
6	*Retire Campbell 1 , Retrofit Karn 1 & Karn 2 and Campbell 2 & 3; 1,000 MW Max Purchases, Optimized with New Gas*	*N/a*	*0.8%*	*-1.2%*	*-1.0%*
7	*Retire Campbell 2; Retrofit Karn 1 & Karn 2 and Campbell 1 & 3; 1,000 MW Max Purchases, Optimized with New Gas*	*N/a*	*0.3%*	*-1.3%*	*-1.5%*
8	*Retire Campbell 3 , Retrofit Karn 1 & Karn 2 and Campbell 1 &2; 1,000 MW Max Purchases, Optimized with New Gas*	*N/a*	*2.7%*	*0.0%*	*-1.0%*
9	*Retire Karn 1 & 2 ; Retrofit Campbell 1 to 3; 1,000 MW Max Purchases, Optimized with New Gas*	*N/a*	*1.0%*	*-1.8%*	*-2.2%*
10	*Retire Campbell 1 & 2 ; Retrofit Karn 1 & 2 and Campbell 3; 1,000 MW Max Purchases, Optimized with New Gas*	*N/a*	*0.1%*	*-2.7%*	*-3.0%*

The second major finding is that the Company did not prepare an adequate evaluation of the risks associated with its proposed Continued Operation strategy. In particular it did not the sensitivity of its potential resource strategies to the possibility of higher costs to comply with NAAQS and Section 316(b), or the possibility of higher carbon emission allowance costs over the 2012 to 2040 period.

Q. Please summarize you major conclusion and recommendations based on those results

A. My conclusion is that the Company's proposal to retrofit all Big Five units is not reasonable.

Based upon those findings, and my conclusion, I recommend that the Commission not approve the Company's request for rate relief to fund its proposed capital expenditures for environmental control measures at Campbell units 1 and 2. I further recommend that the Commission not approve the Company's request for rate relief to fund its proposed capital expenditures for environmental control measures at Karn units 1 and 2 until the Company submits updated economic evaluations for each unit. The updated evaluations should include a case based upon an up-to-date reasonable projection of natural gas prices and the Company compliance cost assumptions, a second case which considers a reasonable projection of carbon allowance costs, a third case which assumes each unit will require a cooling tower to comply with Section 316(b), and a fourth case which assumes both a reasonable projection of carbon costs and a cooling tower.

Q. Does this complete your Direct Testimony?

A. Yes.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA.
Senior Consultant, 2006 to present.
Provides analysis and expert testimony regarding planning, market structure, ratemaking and supply contracting issues in the electricity and natural gas industries. Planning cases include evaluation of resource options for meeting tighter air emission standards (e.g. retrofit vs. retire coal units) in Kentucky, West Virginia and U.S. Midwest as well as development of long-term projections of avoided costs of electricity and natural gas in New England. Ratemaking cases include electric utility load retention rate in NS, various gas utility rate cases and evaluation of proposals for advanced metering infrastructure (smart grid or AMI) and dynamic pricing in MD, PA, NJ, AR, ME, NV, DC and IL.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006, *Senior Consultant*, 1998–2004.
Expert testimony and litigation support in energy contract price arbitration proceedings and various ratemaking proceedings. Productivity improvement project for electric distribution companies in Abu Dhabi. Analyzed market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Manager of Natural Gas Program, 1986–1997.
Presented expert testimony on rates for unbundled retail services, analyzed the options for purchasing electricity and gas in deregulated markets, prepared testimony and reports on a range of gas industry issues including market structure, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada.
Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986.
Assistant Deputy Minister of Energy 1983–1986.
Director of Energy Resources 1982-1983
Assistant to the Deputy Minister 1981-1982

Nova Scotia Research Foundation, Dartmouth, Canada, *Consultant*, 1978–1981.
Canadian Keyes Fibre, Hantsport, Canada, *Project Engineer,* 1975–1977.
Imperial Group Limited, Bristol, England, *Management Consultant*, 1973–1975.

EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
B.Eng., Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973

TESTIMONY

Jurisdiction	Company	Docket	Date	Issue
Illinois	Ameren Illinois	12-0244	August 2012	Advanced metering infrastructure (AMI)
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Kentucky	Kentucky Power Company	2011-00401	March 2012	CPCN for Big Sandy Unit 2
Nova Scotia	Heritage Gas	NG-HG-R-11	September 2011 and May 2012	Cost allocation and rate design
Arkansas	Oklahoma Gas & Electric	10-109-U	May 2011 and June 2011	Advanced metering infrastructure (AMI)
Texas	Texas-New Mexico Power	PUC 38306	April 2011	Advanced metering infrastructure (AMI)
Arkansas	Oklahoma Gas & Electric	10-067-U	March 2011	Windspeed transmission line
Pennsylvania	PECO Energy	M-2009-2123944	December 2010 and January 2011	Dynamic Pricing
Arkansas	Oklahoma Gas & Electric	10-073-U	November 2010	Wind power purchase agreement
Indiana	Vectren Energy Delivery of Indiana	Cause No. 43839	July 2010	Sales Reconciliation Adjustment

Jurisdiction	Company	Docket	Date	Issue
Alaska	Enstar Natural Gas	U-09-069 and U-09-070	March 2010	Rate Design
Pennsylvania	Allegheny Power	M-2009-2123951	March 2010 and October 2009.	Smart meters / advanced metering infrastructure (AMI)
Massachusetts	All Massachusetts regulated electric and gas utilities	D.P.U. 09-125 et al.	December 2009	Avoided Energy Supply Costs in New England
Pennsylvania	Metropolitan Edison Company	M-2009-2123950	October 2009.	Smart meters / AMI
Maryland	Potomac Electric Power	No. 9207	October 2009 and July 2011.	Smart meters / AMI
Maryland	Baltimore Gas and Electric	No. 9208	October 2009 and July 2010.	Smart meters / AMI
New Jersey	Jersey Central Power & Light	EO08050326 and EO08080542	July 2009	Demand response programs
Minnesota	CenterPoint Energy	G-008/GR-08-1075	June 2009.	Conservation Enabling Rider
South Carolina	Progress Energy Carolinas	2008-251-E	January 2009.	Compensation for efficiency programs
North Carolina	Progress Energy Carolinas	No. E-2 sub 931	December 2008.	Compensation for efficiency programs
Maine	Central Maine Power	2007 – 215	October 2008.	Smart meters / AMI
North Carolina	Duke Energy Carolinas	E-7 Sub 831	June 2008	Compensation for efficiency programs (save-a-watt)

Jurisdiction	Company	Docket	Date	Issue
Indiana	Duke Energy Indiana	No. 43374	May 2008.	Compensation for efficiency programs (save-a-watt)
Pennsylvania	PECO Energy Company	P-2008-2032333	June 2008.	Residential Real Time Pricing pilot
Arkansas	Entergy Arkansas	06-152-U Phase II A	October 2007	Interim tolling agreement and proposed allocation of Ouachita Power capacity
Washington	Avista Utilities	UE-070804 and UG-070805	September 2007.	Cost allocation, rate design
Arkansas	Entergy Arkansas	06-152-U	January 2007.	Need for load-following capacity
Michigan	Consumers Energy Company	U-14992	December 2006.	Proposed sale of Palisades nuclear plant and associated power purchase
Connecticut	Connecticut Natural Gas Corporation	06-03-04PH01	November 2006.	Gas supply strategy and proposed rate recovery
Michigan	Consumers Energy Company	U-14274-R	October 2006.	Purchases from Midland Cogeneration Venture Limited Partnership
Illinois	WPS Resources and Peoples Energy Corporation	Docket No. 06-0540	October and December 2006.	Service quality metrics and benchmarks
Arizona	Arizona Public Service	E-01345A-05-0816	August 2006 and September 2006.	Hedging strategy and base fuel recovery amount
Ontario	Transalta Energy Corporation versus Bayer Inc.	Private arbitration	January 2006.	Price for steam under a 20-year contract

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power vs Shell	Private arbitration	October 2005.	New natural gas price under a 10-year supply contract
New York	Consolidated Edison of New York, New York State Electric and Gas	Case 00-M-0504	September and October 2002.	Rates for unbundled supply, distribution, metering and billing services
New Jersey	Public Service Electric and Gas	BPU Docket GM00080564	April 2001.	Proposed transfer of gas contracts to an unregulated affiliate and supply contract associated with that transfer.
Nova Scotia	Sempra	NSUARB-NG-SEMPRA-SEM-00-08	February 2001.	Proposed distribution service tariff rates including market-based rates
New Jersey	Generic proceeding	BPU Docket EX99009676	March 2000.	Design and pricing of unbundled customer account services
United States of America	Bonneville Power Administration	BPA Docket WP-02	November 1999.	Functionalization of communication plant
South Carolina	South Carolina Electric and Gas	99-006-G	October 1999.	Purchased gas costs
New Jersey	Public Service Electric & Gas, South Jersey Gas, New Jersey Natural Gas and Elizabethtown Gas	GO99030122–GO99030125	July and September 1999.	Service unbundling policies and rates

Jurisdiction	Company	Docket	Date	Issue
Maine	Northern Utilities Inc.	Docket 97-393	September and December 1998.	Rate redesign and partial unbundling
Pennsylvania	Peoples Natural Gas	R-00984281; A-12250F0008	May 1998.	Purchased gas costs and proposal to transfer production assets to affiliate
New Jersey	Rockland Electric Company	BPU E09707 0465 OAL PUC-7309-97 BPU E09707 0464 OAL PUC-7310-97	January and March 1998.	Rate unbundling
New Jersey	Jersey Central Power & Light d/b/a GPU Energy.	BPU EO9707 0459 OAL PUC- 7308-97 BPU E09707 0458 OAL PUC-7307-97	November 1997.	Rate unbundling
Pennsylvania	Equitable Gas Company	R-00963858	June and July 1997.	Rate structure proposals
Pennsylvania	Peoples Natural Gas Company	R-00973896 and A-0012250F-0007	May 1997.	Purchased gas costs, proposal to transfer producing assets to CNG Producing Company and proposed Migration Rider
South Carolina	South Carolina Pipeline Corporation	97-009-G	April 1997.	Reasonableness of proposal to acquire additional pipeline capacity
FERC	Transcontinental Gas Pipeline	RP95-197-001; RP97-71-000	March 1997.	Review of proposed rolled-in ratemaking for Leidy Line incremental facilities
Arkansas	Arkla	95-401-U	September 1996.	Gas purchasing and transportation plan

Jurisdiction	Company	Docket	Date	Issue
Maine	Northern Utilities Inc. and Granite State Gas Transmission	95-480; 95-481	April 1996	Precedent Agreement for LNG Storage Service and PNGTS Transportation Service
Rhode Island	ProvGas	2025	November 1995	Settlement Agreement
Pennsylvania	T.W. Phillips Gas and Oil	R-953406	October 1995	Cost allocation, rate design
Illinois	Northern Illinois Gas	95-0219	August1995	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-953316	May 1995	Purchased gas costs
Pennsylvania	Peoples Natural Gas	R-943252	May 1995	Cost allocation, rate design
South Carolina	South Carolina Pipeline Corporation.	94-007-G	April 1995	1994 purchased gas costs
Pennsylvania	National Fuel Gas Distribution Corp	R-943207	March 1995	1995 Purchased Gas Adjustment filing
Pennsylvania	UGI Utilities	R-00943063	December 1994	FERC Order 636 transition cost tariff
South Carolina	South Carolina Electric and Gas Co.	94-008-G	October 1994	1994 Purchased Gas Adjustment
Oklahoma	Public Service of Oklahoma	PUD 920 001342	September and November 1994	Gas supply strategy, transportation and agency services and rate mechanism

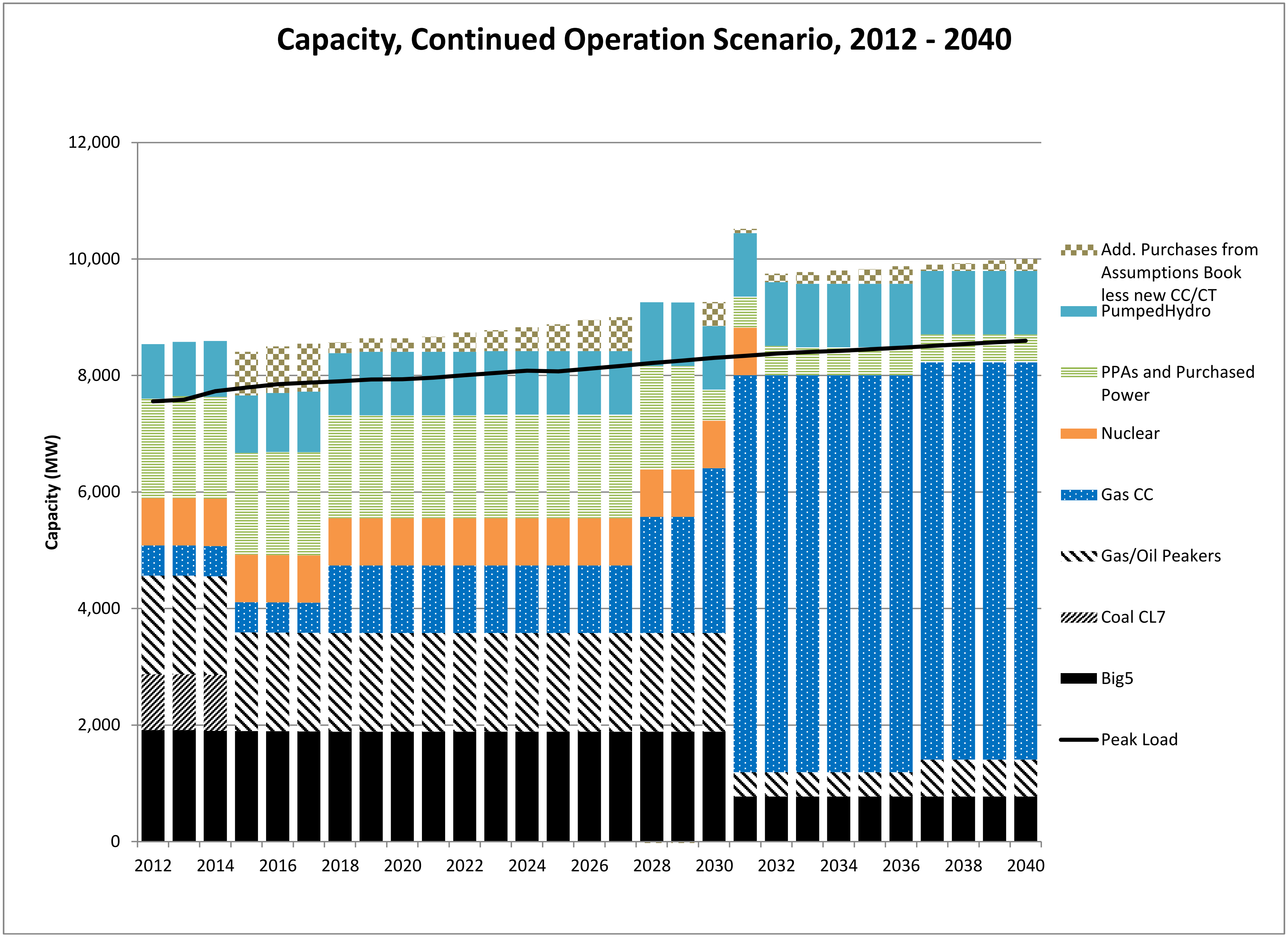
Jurisdiction	Company	Docket	Date	Issue
Pennsylvania	Pennsylvania Gas and Water	R-943078	September 1994	Market Sensitive Sales Service
Massachusetts	Generic proceeding	D.P.U. 93-141-A	September 1994	Policies on interruptible transportation and capacity release
Hawaii	HELCO	7259	August 1994	DSM programs for competitive energy end-use markets, multi-attribute analysis
Pennsylvania	Pennsylvania Gas and Water	R-00943066	July 1994	1994 Purchased Gas Adjustment
Pennsylvania	Pennsylvania Gas and Water	R-942993; R-942993 C0001-C0004	May 1994	Take-or-Pay Cost Recovery
Pennsylvania	Columbia Gas of Pennsylvania	R-943001	May 1994	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-943029	May 1994	1994 Purchased Gas Adjustment; Negotiated Sales Service
Pennsylvania	Peoples Natural Gas	R-932866; R-932915	March 1994	Cost allocation, rate design
Kansas	Generic proceeding	180; 056-U	February 1994	IRP rules for gas utilities
Arizona	Citizens Utility Company Arizona Gas Division	E-1032-93-111	December 1993	Cost allocation, rate design
Hawaii	HECO	7257	December 1993	Residential sector water heating program
Hawaii	GASCO	7261	September 1993	IRP

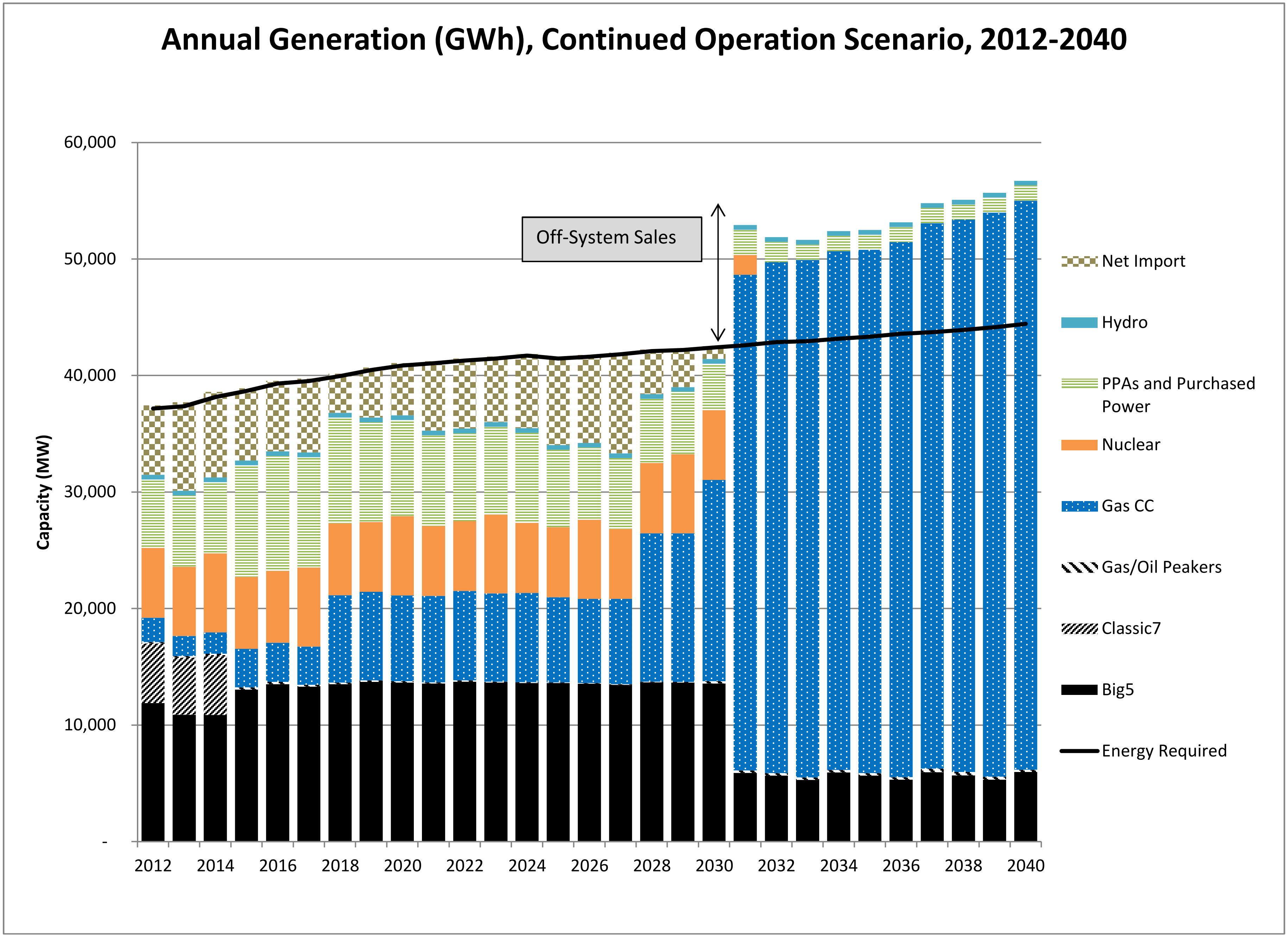
Jurisdiction	**Company**	**Docket**	**Date**	**Issue**
Pennsylvania	Pennsylvania Gas and Water	R-932655; R-932655 C001; R-932655 C002	September 1993	Balancing service
Pennsylvania	Pennsylvania Gas and Water	R-932676	July 1993	1993 Purchased Gas Adjustment filing
Rhode Island	Providence Gas Company	2025	April 1993	IRP
Pennsylvania	Equitable	I-900009; C-913669	March 1993	Charges for transportation service and cost allocation methods in general
Arkansas	Arkla Energy Resources, Arkansas Louisiana Gas	92-178-U	August 1992	Gas cost and purchasing practices
Colorado	Generic proceeding	91R-642EG	August 1992	Gas integrated resource planning rule
Pennsylvania	Pennsylvania Gas and Water	R-00922324	July 1992	1992 Purchased Gas Adjustment filing
Pennsylvania	Peoples Natural Gas Company	R-922180	May 1992	Cost allocation, rate design
Michigan	Consumers Power Company	U-10030	April 1992	Gas Cost Recovery Plan, role of demand-side management as a resource in five-year forecast and supply plan
Pennsylvania	T.W. Phillips	R-912140	March 1992	1992 Purchased Gas Adjustment

Jurisdiction	Company	Docket	Date	Issue
FERC	Columbia Gas Transmission and Columbia Gulf Transmission	RP91-161-000 et al RP91-160-000 et al.	February 1992	Cost allocation, rate design
Arkansas	Arkla Energy Resources	91-093-U	February 1992	Base cost of gas
New Hampshire	Energy North Natural Gas	DR90-183	January 1992	Cost allocation, rate design
Arizona	Southwest Gas Corporation	U-1551-89-102 & U-1551-89-103; U-1551-91-069	September 1991	Gas Procurement Practices and Purchased Gas Costs
Maryland	Baltimore Gas and Electric	8339	July 1991	Cost allocation, rate design
Rhode Island	Bristol and Warren Gas	1727	June 1991	Gas procurement
New Mexico	Gas Company of New Mexico	2367	June 1991	Gas transportation policies
Pennsylvania	T.W. Phillips	R-911889	March 1991	Gas supply
Michigan	Michigan Gas Company	U-9752	March 1991	Gas Cost Recovery Plan
Arkansas	Arkla	90-036-U	August and September 1990	Gas supply contracts, including Arkla-Arkoma transactions
Arizona	Southern Union Gas	U-1240-90-051	August 1990	Cost Allocation and Rate Design
Utah	Mountain Fuel Supply	89-057-15	July1990	Cost Allocation and Rate Design

Jurisdiction	Company	Docket	Date	Issue
Pennsylvania	Equitable Gas Company	R-901595	June 1990	Cost Allocation and Rate Design
West Virginia	APS	90-196-E-GI ; 90-197-E-GI	May 1990	Coal supply strategy
Pennsylvania	T.W. Phillips Gas and Oil Co.	R-891572	March 1990	Purchased Gas Costs
Colorado	Generic proceeding	89R-702G	January 1990	Policies and rules for gas transportation service
Arizona	Generic proceeding	U-1551-89-102 and U-1551-89-103	October 1989	Regulatory Oversight of Purchased Gas Costs
Rhode Island	Narragansett Electric Company	1938	October 1989	Sales Forecast, Cost Allocation, rate design
Pennsylvania	Pennsylvania Gas and Water	R891293	July 1989	Purchased Gas Costs
Pennsylvania	Columbia Gas of Pennsylvania	R891236	May 1989	Take-or-Pay Cost Recovery
New Jersey	Elizabethtown Gas Company	GR 88081-019	December 1988and February 1989	Take-or-Pay Cost Recovery
Montana	Montana-Dakota Utilities	87.7.33; 88.2.4; 88.5.10; 88.8.23	December1988	Gas Procurement, Transportation Service Gas Adjustment Clause

Jurisdiction	Company	Docket	Date	Issue
New Jersey	South Jersey Gas Company	GR 88081-019 and GR 88080-913-	November 1988 and February 1989	Take-or-Pay Cost Recovery
New Jersey	Public Service Electric and Gas	GR 88070-877	October 1988 and February 1989	Take-or-Pay Cost Recovery
District of Columbia	District of Columbia Natural Gas	Formal Case 874	September 1988	Gas Acquisition, Gas Cost Allocation, take or pay-costs; Regulatory Oversight
Illinois	Generic proceeding	88-0103	July 1988	Take-or-Pay Cost Recovery
West Virginia	Generic proceeding	240-G	June 1988	Gas Transportation Rate Design
Pennsylvania	Pennsylvania Gas & Water	R-880958	June 1988	Purchased Gas Adjustment
Utah	Mountain Fuel Supply	86-057-07	March 1988	Gas Transportation Rate Design
South Carolina	South Carolina Electric & Gas	87-227-G	September 1987	Gas Supply and Rate Design
Arizona		U-1345-87-069	September 1987	Fuel Adjustment Clause


Capacity, Continued Operation Scenario, 2012 - 2040
Capacity (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Add. Purchases from Assumptions Book less new CC/CT
PumpedHydro
PPAs and Purchased Power
Nuclear
Gas CC
Gas/Oil Peakers
Coal CL7
Big5
Peak Load


Annual Generation (GWh), Continued Operation Scenario, 2012-2040
Capacity (MW)
60,000
50,000
40,000
30,000
20,000
10,000
-
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Off-System Sales
Net Import
Hydro
PPAs and Purchased Power
Nuclear
Gas CC
Gas/Oil Peakers
Classic7
Big5
Energy Required

Environmental Compliance Capital Costs, Big 5 Units

Units	Control Measures	Consumers Energy Estimates: Direct Testimony of Popa, Exh. A-40 (NOM $,000)	Supplemental Testimony of Popa, Exhs. A-39 (revised) and A-41 (revised) (NOM$, 000)	Capacity after Derates from Environmental Control (MW)	Capital cost of compliance, $ per kW
		A	B	C	D = B / C
Karn Unit 1					
1	ACI	$ 6,600	$ 6,600		
2	SDA	$ 144,425	$ 144,426		
3	SEEG	$ 21,591	$ 21,591		
4	316(b)	$ 25,057	$ 25,057		
5	***Subtotal***	*$ 197,673*	***$ 197,674***	**253**	**$ 781**
Karn Unit 2					
6	ACI	$ 7,000	$ 7,000		
7	SDA	$ 106,234	$ 106,234		
8	SEEG	$ 22,473	$ 22,473		
9	316(b)	$ 25,057	$ 25,057		
10	***Subtotal***	*$ 160,764*	***$ 160,764***	**258**	**$ 623**
Campbell Unit 1					
11	DSI	$ 22,500	$ 22,500		
12	PJFF	$ 109,913	$ 109,914		
13	ACI	$ 8,925	$ 8,925		
14	*SCR*		*$ -*		
15	SEEG	$ 18,420	$ 18,420		
16	316(b)	$ 21,369	$ 21,369		
17	***Subtotal***	*$ 181,127*	***$ 181,128***	**254**	**$ 713**
Campbell Unit 2					
18	SCR	$ 119,741	$ 119,741		
19	PJFF	$ 119,350	$ 119,350		
20	SDA/DSI	$ 171,947	$ 33,592		
21	ACI	$ 9,086	$ 9,086		
22	SEEG	$ 24,559	$ 24,559		
23	316(b)	$ 21,369	$ 21,369		
24	***Subtotal***	*$ 466,052*	***$ 327,697***	**248.2**	**$ 1,320**
Campbell Unit 3					
25	PJFF	$ 225,680	$ 219,408		
26	SDA	$ 233,862	$ 299,700		
27	ACI	$ 12,050	$ 10,292		
28	SEEG	$ 44,733	$ 44,733		
29	316(b)	$ -	$ -		
30	***Subtotal***	*$ 516,325*	***$ 574,133***	**827.4**	**$ 694**
31	***Unit Specific Costs Subtotal***	*$ 1,521,941*	***$ 1,441,396***	**1840.6**	**$ 783**
Site specific costs					
32	**KARN RCRA**	*$ 1,759*	*$ 1,759*		
33	**Campbell RCRA**	*$ 49,236*	*$ 3,828*		
34	**TOTAL**	**$ 1,572,936**	**$ 1,446,983**	**1,841**	$ 786

Notes	
1	ACI is Activated Carbon Injection, a compliance measure to remove mercury
2	SDA is Spray Dry Absorber, a compliance measure for acid gas control
3	SEEG are Steam Electric Effluent Guidelines that regulate industrial wastewaters
11	DSI is Dry Sorbent Injection, a compliance measure for acid gas control
14	SCR is Selective Catlytic Reduction, a compliance measure for NO_x
4	316(b) is a section of the Clean Water Act addressing impacts of cooling water usage on fish populations
12	PJFF is Pulse Jet Fabric Filter, a compliance measure to remove mercury in combination with ACI
32	RCRA is the Resource Conservation and Recovery Act, addressing Coal Combustion Residual (CCR) management

Environmental Compliance Capital Costs, Big 5 Units, Including Cooling Tower Costs

Units	Control Measures	Consumers Energy Estimates				Consumers Energy Estimates including Cooling Towers			
		Direct Testimony of Popa, Exh. A-40 (NOM $,000)	Supplemental Testimony of Popa, Exhs. A-39 (revised) and A-41 (revised) (NOM$, 000)	Capacity after Derates from Environmental Control (MW)	Capital cost of compliance, $ per kW	Cost of Closed Cycle Cooling Towers (NOM$, 000)	Differential, Cost of Cooling Towers less estimates in Popa Supplemental testimony (NOM$, 000)	Total capital Costs including incremental cost of cooling towers (NOM$, 000)	Capital cost of compliance per kW with Cooling Towers
		A	B	C	D = B / C	E	F = E - B	G = D + F	H = G / C
Karn Unit 1									
1	ACI	$ 6,600	$ 6,600						
2	SDA	$ 144,425	$ 144,426						
3	SEEG	$ 21,591	$ 21,591						
4	316(b)	$ 25,057	$ 25,057			$58,063	$33,006		
5	***Subtotal***	*$ 197,673*	***$ 197,674***	**253**	**$ 781**			$ 230,680	$ 912
Karn Unit 2									
6	ACI	$ 7,000	$ 7,000						
7	SDA	$ 106,234	$ 106,234						
8	SEEG	$ 22,473	$ 22,473						
9	316(b)	$ 25,057	$ 25,057			$58,063	$33,006		
10	***Subtotal***	*$ 160,764*	***$ 160,764***	**258**	**$ 623**			$ 193,770	$ 751
Campbell Unit 1									
11	DSI	$ 22,500	$ 22,500						
12	PJFF	$ 109,913	$ 109,914						
13	ACI	$ 8,925	$ 8,925						
14	*SCR*		*$ -*						
15	SEEG	$ 18,420	$ 18,420						
16	316(b)	$ 21,369	$ 21,369			$70,837	$49,468		
17	***Subtotal***	*$ 181,127*	***$ 181,128***	**254**	**$ 713**			$ 230,596	$ 908
Campbell Unit 2									
18	SCR	$ 119,741	$ 119,741						
19	PJFF	$ 119,350	$ 119,350						
20	SDA/DSI	$ 171,947	$ 33,592						
21	ACI	$ 9,086	$ 9,086						
22	SEEG	$ 24,559	$ 24,559						
23	316(b)	$ 21,369	$ 21,369			$70,837	$49,468		
24	***Subtotal***	*$ 466,052*	***$ 327,697***	**248.2**	**$ 1,320**			$ 377,165	$ 1,520
Campbell Unit 3									
25	PJFF	$ 225,680	$ 219,408						
26	SDA	$ 233,862	$ 299,700						
27	ACI	$ 12,050	$ 10,292						
28	SEEG	$ 44,733	$ 44,733						
29	316(b)	$ -	$ -			306,265	$306,265		
30	***Subtotal***	*$ 516,325*	***$ 574,133***	**827.4**	**$ 694**			$ 880,398	$ 1,064
31	***Unit Specific Costs Subtotal***	*$ 1,521,941*	***$ 1,441,396***	**1840.6**	**$ 783**	**564,066**	**471,214**	**1,912,610**	$ 1,039
Site specific costs									
32	**KARN RCRA**	*$ 1,759*	*$ 1,759*					$ 1,759	
33	**Campbell RCRA**	*$ 49,236*	*$ 3,828*					$ 3,828	
34	**TOTAL**	**$ 1,572,936**	**$ 1,446,983**	**1,841**	$ 786		**$ 471,214**	**$ 1,918,197**	$ 1,042

Notes	
	Control measures are defined on Page 1
E	**Costs (excluding COR & AFUDC) for cooling towers given in Closed-Cycle Retrofit Study, provided in response to 17087-MEC-CE-318**

Appendix D-1

Consumers Energy

Electric Generation - Plant Retirement Dates
2009 Plant Depreciation Study (Case U-16054)

Plant Name	Year Installed	Revised Retirement Date	Service Life Remaining (2009-Retirement Year)		Plant Balance Excluding Land and Land Rights	Estimated Decommissioning Cost	ECI Retirement Yr Base = 1.10	Inflated Demolition Cost	Net Salvage %	Net Salvage % wo Inflation
Steam Plants										
JH Campbell Unit 1	1962	2030	21							
JH Campbell Unit 2	1967	2030	21	Units 1-2	416,158,514	46,010,000	1.97	82,399,727	-19.80%	-11.06%
JH Campbell Unit 3	1980	2040 **	31	Unit 3	1,032,133,261	86,862,000	2.61	206,099,836	-19.97%	-8.42%
BC Cobb Unit 1	1949	2020	11							
BC Cobb Unit 2	1949	2020	11							
BC Cobb Unit 3	1949	2020	11	Units 1-3	24,987,943	3,186,787	1.44	4,171,794	-16.70%	-12.75%
BC Cobb Unit 4	1956	2025	16							
BC Cobb Unit 5	1957	2025	16	Units 4-5	159,591,754	20,353,213	1.69	31,257,493	-19.59%	-12.75%
DE Karn Unit 1	1959	2030	21							
DE Karn Unit 2	1961	2030	21	Units 1-2	326,411,381	46,010,000	1.97	82,399,727	-25.24%	-14.10%
DE Karn Unit 3	1975	2030	21							
DE Karn Unit 4	1977	2030	21	Units 3-4	283,435,575	11,770,000	1.97	21,079,000	-7.44%	-4.15%
JC Weadock Unit 7	1955	2025	16							
JC Weadock Unit 8	1958	2025	16	Units 7-8	118,893,980	47,080,000	1.69	72,303,217	-60.81%	-39.60%
JR Whiting Units 1-3	1952	2025	16		138,958,654	29,960,000	1.69	46,011,138	-33.11%	-21.56%
Hydro Plants										
Alcona	1924	2034	25		3,643,806	16,349,179	2.21	32,846,988	-901.45%	-448.68%
Calkins Bridge (Allegan) *	1935	2040 **	31		1,956,508	51,157,463	2.61	121,382,707	-6204.05%	-2614.73%
Cooke	1911	2034	25		3,149,551	26,568,052	2.21	53,377,631	-1694.77%	-843.55%
Croton	1906	2034	25		8,273,104	33,642,926	2.21	67,591,697	-817.01%	-406.65%
Five Channels	1912	2034	25		3,850,729	14,136,210	2.21	28,400,931	-737.55%	-367.10%
Foote	1918	2034	25		3,986,113	23,022,871	2.21	46,255,041	-1160.40%	-577.58%
Hardy	1931	2034	25		8,114,856	50,288,290	2.21	101,033,747	-1245.05%	-619.71%
Hodenpyl	1925	2034	25		6,731,113	57,490,196	2.21	115,503,030	-1715.96%	-854.10%
Loud	1913	2034	25		3,149,663	14,153,936	2.21	28,436,545	-902.84%	-449.38%
Mio	1916	2034	25		3,146,526	17,299,308	2.21	34,755,883	-1104.58%	-549.79%
Rogers	1906	2034	25		4,980,014	22,380,679	2.21	44,964,818	-902.91%	-449.41%
Tippy	1918	2034	25		7,603,002	28,915,450	2.21	58,093,768	-764.09%	-380.32%
Webber	1907	2041 **	32		6,663,092	24,835,338	2.69	60,733,690	-911.49%	-372.73%
							Excludes 331.3			
Combustion Turbine Plants										
Campbell A	1968	2015	6		1,749,627	375,570	1.25	426,784	-24.39%	-21.47%
Gaylord Units 1-4	1966	2015	6							
Gaylord Unit 5	1968	2015	6	Units 1-5	7,137,629	1,116,010	1.25	1,268,193	-17.77%	-15.64%
Mobile Generator	2002	2013	4		417,514	0	1.18	0	0.00%	0.00%
Morrow A	1968	2015	6					0		
Morrow B	1969	2015	6	Units A & B	3,471,764	751,140	1.25	853,568	-24.59%	-21.64%
Straits	1969	2015	6		2,147,711	375,570	1.25	426,784	-19.87%	-17.49%
Thetford Units 1-4	1970	2015	6					0		
Thetford Units 5-9	1971	2015	6	Units 1-9	26,087,845	1,677,760	1.25	1,906,545	-7.31%	-6.43%
Weadock A	1968	2015	6		1,613,356	375,570	1.25	426,784	-26.45%	-23.28%
Whiting A	1968	2015	6		1,736,479	375,570	1.25	426,784	-24.58%	-21.63%
Zeeland	2002	2030	21		348,168,074	6,407,160	1.97	11,474,641	-3.30%	-1.84%

* Currently in process of relicensing - planned 30 year renewal from the FERC

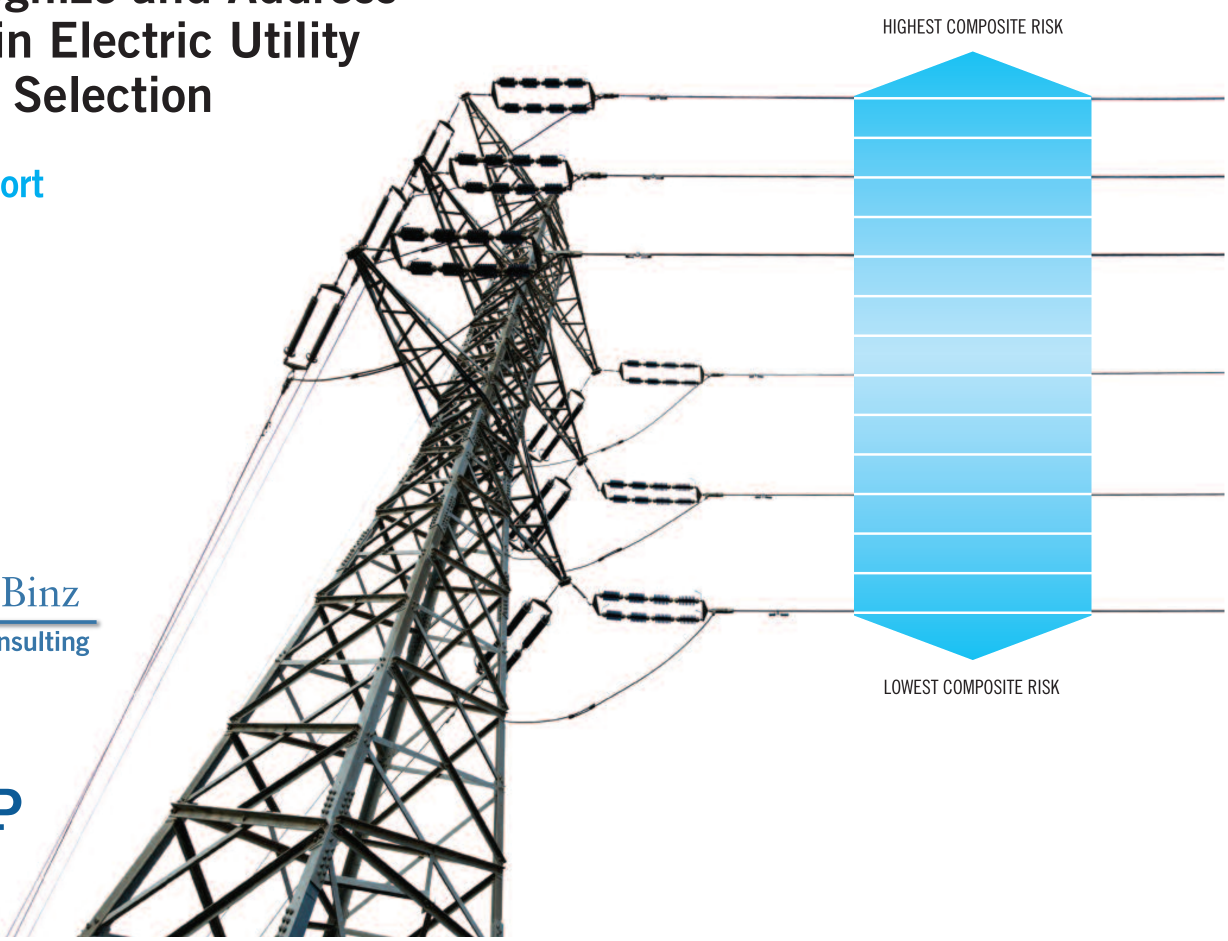
** ECI index is only available through 2039. Factor for years beyond 2039 to determine the inflated decommissioning cost is projected based on 30 year average.

Ceres

PRACTICING RISK-AWARE ELECTRICITY REGULATION: What Every State Regulator Needs to Know

How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection

A Ceres Report
April 2012



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Ceres is an advocate for sustainability leadership. It leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges. Ceres also directs the Investor Network on Climate Risk (INCR), a network of 100 institutional investors with collective assets totaling about $10 trillion.

ACKNOWLEDGEMENTS

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ABOUT THIS REPORT

AUDIENCE

This report is primarily addressed to **state regulatory utility commissioners**, who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment. It is hoped that this approach will result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Additionally, this report seeks to present a unique discussion of risk and a perspective on appropriate regulatory approaches for addressing it that will interest numerous **secondary audiences**, including **utility managements, financial analysts, investors, electricity consumers, advocates, state legislatures and energy offices, and other stakeholders** with a particular interest in ensuring that electric system resource investments—which could soon reach unprecedented levels—are made thoughtfully, transparently and in full consideration of all associated risks.

SCOPE

While we believe that the approach described herein is applicable to a broad range of decisions facing state regulators, the report focuses primarily on resource investment decisions by investor-owned electric utilities (IOUs), which constitute roughly 70 percent of the U.S. electric power industry. The findings and recommendations may be of particular interest to regulators in states facing substantial coal generating capacity retirements and evaluating a spectrum of resource investment options.

AUTHORS

Ron Binz, the lead author of this report, is a 30-year veteran of utility and energy policy and principal with Public Policy Consulting. Most recently, he served for four years as the Chairman of the Colorado Public Utilities Commission where he implemented the many policy changes championed by the Governor and the Legislature to bring forward Colorado's "New Energy Economy." He is the author of several reports and articles on renewable energy and climate policy has testified as an expert witness in fifteen states.

Richard Sedano is a principal with the Regulatory Assistance Project (RAP), a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to policymakers and regulators on a broad range of energy and environmental issues. RAP is widely viewed as a source of innovative and creative thinking that yields practical solutions. RAP members meet directly with government officials, regulators and their staffs; lead technical workshops and training sessions; conduct in-house research and produce a growing volume of publications designed to better align energy regulation with economic and environmental goals.

Denise Furey has over 25 years of experience with financial institutions, structuring and analyzing transactions for energy and utility companies. In 2011 she founded Regent Square Advisors, a consulting firm specializing in financial and regulatory concerns faced by the sector. She worked with Citigroup covering power and oil & gas companies, and worked with Fitch Rating, Enron Corporation and MBIA Insurance Corporation. Ms. Furey also served with the Securities and Exchange Commission participating in the regulation of investment companies.

Dan Mullen, Senior Manager for Ceres' Electric Power Programs, works to identify and advance solutions that will transform the U.S. electric utility industry in line with the urgent goal of sustainably meeting society's 21st century energy needs. In addition to developing Ceres' intellectual capital and external partnerships, he has engaged with major U.S. electric utilities on issues related to climate change, clean energy and stakeholder engagement, with a particular focus on energy efficiency. A Stanford University graduate, Dan has also raised more than $5 million to support Ceres' climate change initiatives and organizational development.

TABLE OF CONTENTS

TABLE OF FIGURES

FOREWORD

Today's electric industry faces a stunning investment cycle. Across the country, the infrastructure is aging, with very old parts of the power plant fleet and electric and gas delivery systems needing to be replaced. The regulatory environment is shifting dramatically as rules tighten on air pollution from fossil-burning power plants. Fossil fuel price outlooks have shifted. New options for energy efficiency, renewable energy, distributed generation, and smart grid and consumer technologies are pressing everyone to think differently about energy and the companies that provide it. Customers expect reliable electricity and count on good decisions of others to provide it.

The critical nature of this moment and the choices ahead are the subject of this report. It speaks to key decision-makers, such as: state regulators who have a critical role in determining utility capital investment decisions; utility executives managing their businesses in this era of uncertainty; investors who provide the key capital for utilities; and others involved in regulatory proceedings and with a stake in their outcomes.

The report lays out a suite of game-changing recommendations for handling the tremendous investment challenge facing the industry. As much as $100 billion will be invested each year for the next 20 years, roughly double recent levels. A large portion of those investments will be made by non-utility companies operating in competitive markets. But another large share will be made by utilities—with their (and their key investors') decisions being greatly affected by state regulatory policies and practices.

This is no time for backward-looking decision making. It is vital—for electricity consumers and utilities' own economic viability—that their investment decisions reflect the needs of tomorrow's cleaner and smarter 21st century infrastructure and avoid investing in yesterday's technologies. The authors provide useful advice to state regulators on how they can play a more proactive role in helping frame how electric utilities face these investment challenges.

A key report conclusion in this regard: sensible, safe investment strategies, based on the report's detailed cost and risk analysis of a wide range of generation resources, should include:

- Diversifying energy resource portfolios rather than "betting the farm" on a narrow set of options (e.g., fossil fuel generation technologies and nuclear);
- More emphasis on renewable energy resources such as onshore wind and distributed and utility-scale solar;
- More emphasis on energy efficiency, which the report shows is utilities' lowest-cost, lowest-risk resource.

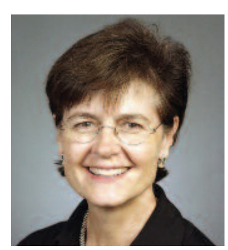
At its heart, this report is a call for "risk-aware regulation." With an estimated $2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall costs over the long term, especially in the face of possible surprises. And utilities' use of robust planning tools needs to be sharpened to incorporate risk identification, analysis, and management.

This report offers some good news amid pervasive uncertainty: the authors point out that planning the lowest-cost, lowest risk investment route aligns with a low-carbon future. From a risk management standpoint, diversifying utility portfolios today by expanding investment in clean energy and energy efficiency makes sense regardless of how and when carbon controls come into play. Placing too many bets on the conventional basket of generation technologies is the highest-risk route, in the authors' analysis.

We're in a new world now, with many opportunities as well as risks. More than ever, the true risks and costs of utility investments should be made explicit and carefully considered as decisions on multi-billion-dollar commitments are made.

As the industry evolves, so too must its regulatory frameworks. The authors point out why and offer guidance about how. This is news regulators and the industry can use.

Susan F. Tierney
Managing Principal
Analysis Group



EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]

Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-fired generating capacity that could be retired in the 2015-2020 timeframe as a result of forthcoming U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulations could require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

Greatly increased utility investment combined with minimal, zero or even declining electricity demand growth means that retail electricity prices for consumers will rise sharply, claiming a greater share of household disposable income and likely leading to ratepayer resistance.[5] Because the U.S. economy was built on relatively cheap electricity—the only thing many U.S. consumers and businesses have ever known—credit rating agencies are concerned about what this dynamic could mean for utilities in the long term. Rating analysts also point out that the overall credit profile for investor-owned utilities (IOUs) could decline even further since utilities' operating cash flows won't be sufficient to satisfy their ongoing investment needs.[6]

It falls to state electricity regulators to ensure that the large amount of capital invested by utilities over the next two decades is deployed wisely. Poor decisions could harm the U.S. economy and its global competitiveness; cost ratepayers, investors and taxpayers hundreds of billions of dollars; and have costly impacts on the environment and public health.

To navigate these difficult times, it is essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition.

CHALLENGES TO EFFECTIVE REGULATION

To be effective in the 21st century, regulators will need to be especially attentive to two areas: identifying and addressing risk; and overcoming regulatory biases.

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is "the expected value of a potential loss." *Higher risk* for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Risks for electric system resources have both time-related and cost-related aspects. *Cost risks* reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. *Time risks* reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. **Figure ES-1** summarizes the many varieties of risk for utility resource investment.

Risk is the expected value of a potential loss. Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Figure ES-1

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

5 Moody's Investors Service, *Special Comment: The 21st Century Electric Utility* (New York: Moody's Investors Service, 2010). Importantly, customers who currently enjoy the lowest electricity rates can expect the largest rate increases, in relative terms, as providers of cheap, coal-generated electricity install costly pollution controls or replace old coal-fired units with more expensive new resources. This dynamic could prove especially challenging for regulators, utilities and consumers in the heavily coal-dependent Midwest.

6 Richard Cortright, "Testimony before the Pennsylvania Public Utility Commission," Harrisburg, Pennsylvania, November 19, 2009, http://www.puc.state.pa.us/general/RegulatoryInfo/pdf/ARRA_Testimony-SPRS.pdf.

RISK

Three observations about risk should be stressed:

1. **Risk cannot be eliminated, but it can be managed and minimized.** Since risks are defined as probabilities, it is by definition probable that some risks will be realized—that, sooner or later, risk will translate into dollars for consumers, investors or both. This report concludes with recommendations for how regulators can minimize risk by practicing "risk-aware regulation."
2. **It is unlikely that consumers will bear the full cost of poor utility resource investment decisions.** The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to burden ratepayers with the full cost of utility mistakes. As a result, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investment decisions than in years past.
3. **Ignoring risk is not a viable strategy.** Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

Traditional utility regulation also contains several built-in biases that effective regulators must overcome.[7] These biases, which result in part from the incentives that traditional regulation provides to utilities, encourage utilities to invest more than is optimal for their customers—which is to say, more than is optimal for the provision of safe, reliable, affordable and environmentally sustainable electricity—and discourage them from investing in the lowest-cost, lowest-risk resources (namely, demand-side resources such as energy efficiency) that provide substantial benefits to ratepayers and local economies. Bias can also lead utilities to seek to exploit regulatory and legislative processes as a means of increasing profits (rather than, for example, improving their own operational efficiencies). Finally, regulators face an inherent information deficit when dealing with utility managements. This can hamper effective collaboration around utility planning, which is arguably the most important function of electricity regulation today.

COSTS AND RISKS OF NEW GENERATION RESOURCES

We closely examine costs and risks of new generation resources for several reasons. First, as the largest share of utility spending in the current build cycle, generation investment is where the largest amount of consumer and investor dollars is at risk. Also, today's decisions about generation investment can trigger substantial future investments in transmission and distribution infrastructure. Proposed power plants can be a lightning rod for controversy, heightening public scrutiny of regulatory and corporate decision-makers. Finally, poor investment decisions about generation resources in IOUs' last major build cycle resulted in tens of billions of dollars of losses for consumers and shareholders.[8] For these and other reasons, it is especially important that regulators address, manage and minimize the risks associated with utility investments in new generation resources.[9]

Ignoring risk is not a viable strategy. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate.

Acquiring new electric system resources involves dimensions of both cost and risk. Of these two dimensions, the tools for estimating the cost elements of new generation, while imperfect, are more fully developed than the risk-related tools. As a starting point for our examination of the relative cost and risk of new generation resources, we rank a wide range of supply-side resources and one demand-side resource (energy efficiency) according to their levelized cost of electricity, or "LCOE" **(Figure ES-2, p. 8)**.[10] This ranking is based on 2010 data and does not include recent cost increases for nuclear or cost decreases for solar PV and wind. Because carbon controls could add significant costs to certain technologies but the exact timing and extent of these costs is unknown, we include a moderate estimate for carbon cost for fossil-fueled resources. And because incentives such as tax credits and loan guarantees can significantly affect LCOE, we examine the LCOE range for each technology with and without incentives where applicable.

7 These biases, which are discussed further in the report, are *information asymmetry; the Averch-Johnson effect; the throughput incentive; "rent-seeking";* and *the "bigger-is-better" bias.*

8 Frank Huntowski, Neil Fisher, and Aaron Patterson, *Embrace Electric Competition or It's Déjà Vu All Over Again* (Concord, MA: The NorthBridge Group, 2008), 18, http://www.nbgroup.com/publications/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf. The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s. Between 1981-91, shareholders lost roughly $19 billion as a result of regulatory disallowances of power plant investments by some regulated utilities; see Thomas P. Lyon and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," *Rand Journal of Economics*, Vol. 36, No. 3 (Autumn 2005): 628–44, http://webuser.bus.umich.edu/tplyon/PDF/Published%20Papers/Lyon%20Mayo%20RAND%202005.pdf. The potential for negative consequences is probably higher today; since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially.

9 While our analysis of risks and costs of new generation resources may be of most interest to regulators in "vertically-integrated" states (where utilities own or control their own generation), it also has implications for regulators in restructured states. Regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as this report makes clear, are utilities' lowest-cost and lowest-risk resources.

10 LCOE indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel). We primarily reference LCOE data compiled by the Union of Concerned Scientists (UCS), which aggregates three common sources of largely consensus LCOE data: the U.S. Energy Information Administration (EIA), the California Energy Commission (CEC) and the investment firm Lazard; see Barbara Freese et al., *A Risky Proposition* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf. LCOE costs for technologies not included in UCS's analysis (viz., biomass co-firing, combined cycle natural gas generation with CCS, and distributed solar) were estimated by the authors based on comparable resources referenced by UCS.

Figure ES-2

RELATIVE COST RANKING OF NEW GENERATION RESOURCES

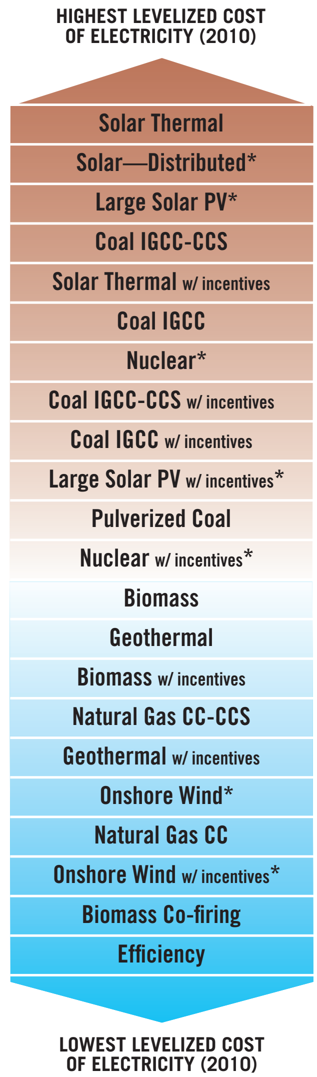
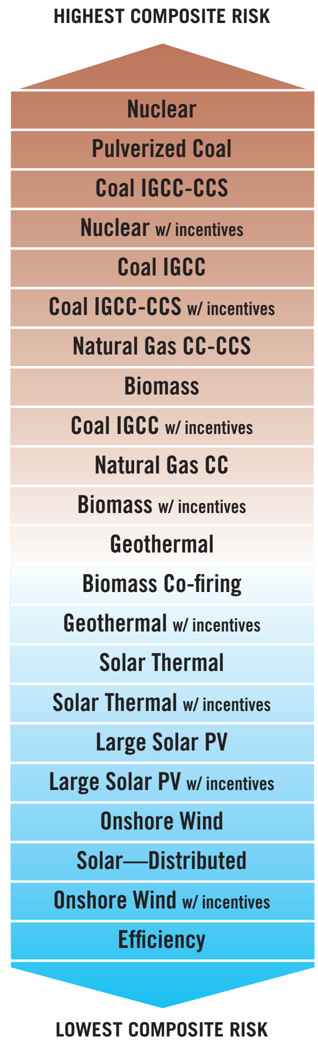


Figure ES-3

RELATIVE RISK RANKING OF NEW GENERATION RESOURCES



** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

But the LCOE ranking tells only part of the story. The *price* for any resource in this list does not take into account the relative *risk* of acquiring it. To establish relative risk of new generation resources, we return to the many risks identified in Figure ES-1 and compress those risks into seven main categories:

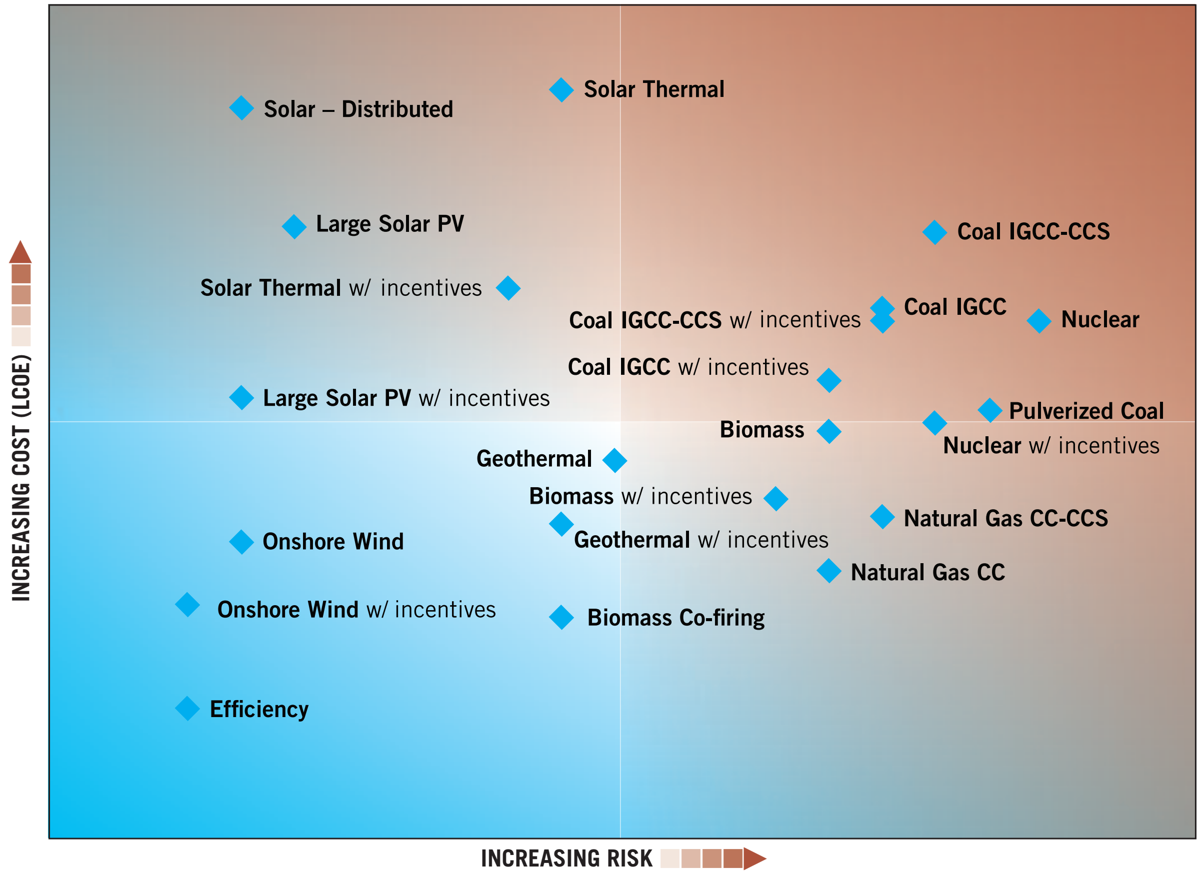
- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

We then evaluate each resource profiled in the LCOE ranking and apply our informed judgment to quantify each resource's relative exposure to each type of risk.[11] This allows us to establish a composite risk score for each resource (with the highest score indicating the highest risk) and rank them according to their relative composite risk profile **(Figure ES-3)**.

11 Risk exposure in each risk category ranges from "None" to "Very High." We assigned scores (None = 0, Very High = 4) to each risk category for each resource and then summed them to establish an indicative quantitative ranking of composite risk. We also tested the robustness of the risk ranking by calculating two additional rankings of the risk scores: one that overweighted the cost-related risk categories and one that overweighted the environmental-related risk categories.

Figure ES-4

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear division between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

With largely consensus quantitative LCOE data, and having developed indicative composite risk scores for each resource, we can summarize relative risks and costs of utility generation resources in a single graph **(Figure ES-4)**.[12]

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states.

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states. The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

12 Resources are assumed to come online in 2015.

PRACTICING RISK-AWARE REGULATION: SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

MANAGING RISK INTELLIGENTLY IS ARGUABLY THE MAIN DUTY OF REGULATORS WHO OVERSEE UTILITY INVESTMENT. EFFECTIVELY MANAGING RISK IS NOT SIMPLY ACHIEVING THE LEAST COST *TODAY*, BUT RATHER IS PART OF A STRATEGY TO *MINIMIZE OVERALL COSTS OVER THE LONG TERM*. WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS SHOULD EMPLOY TO MANAGE AND MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources and energy efficiency. Diversification—investing in different asset classes with different risk profiles—is what allows investors to reduce risk (or "volatility") in their investment portfolios. Similarly, diversifying a utility portfolio by including various supply and demand-side resources that behave independently from each other in different future scenarios reduces the portfolio's overall risk.

2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment. In many vertically integrated markets and in some organized markets, regulators use "integrated resource planning" (IRP) to oversee utilities' capital investments. IRP is an important tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of utility resource options; that the options are examined in a structured, disciplined way; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood by all.

3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk. For example, allowing a current return on construction work in progress (CWIP) to enable utilities to finance large projects doesn't actually reduce risk but rather transfers it from the utility to consumers.[13] While analysts and some regulators favor this approach, its use can obscure a project's risk and create a "moral hazard" for utilities to undertake more risky investments. Utility investment in the lowest-cost and lowest-risk resource, energy efficiency, requires regulatory adjustments that may include decoupling utility revenues from sales and performance-based financial incentives.

4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts. These allow utilities to lock in a price (e.g., for fuel), thereby avoiding the risk of higher market prices later. But these options must be used carefully since using them can foreclose an opportunity to enjoy lower market prices.

5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments. This helps to create a consistent, stable regulatory environment, which is highly valued in the marketplace and ensures that agreed-upon resource plans become reality.

6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk. In "judicial mode," a regulator takes in evidence in formal settings and resolves disputes; in contrast, a regulator operating in "legislative mode" proactively seeks to gather all relevant information and to find solutions to future challenges.

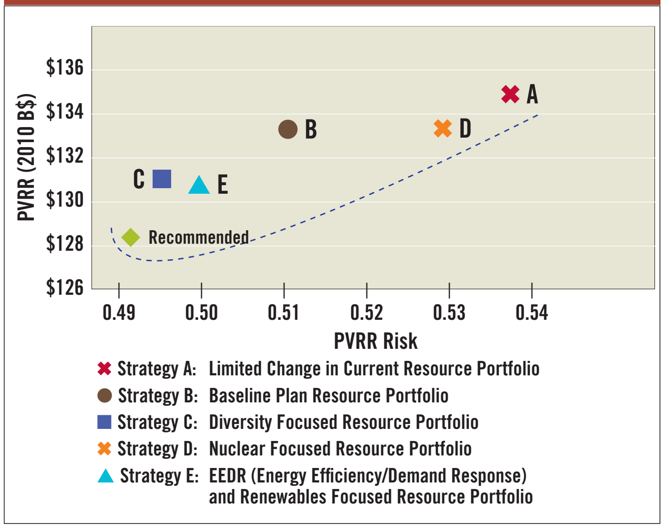
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate. Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades, which led regulators to modernize their tools and experiment with various types of incentive regulation. One area where electricity regulators might profitably question existing practices is rate design; existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

13 For example, the use of CWIP financing in Florida could result in Progress Energy customers paying the utility more than $1 billion for a new nuclear plant (the Levy County Nuclear Power Plant) that may never be built. Florida state law prohibits ratepayers from recouping their investment in Levy or other CWIP-financed projects.

Careful planning is the regulator's primary risk management tool. A recently completed IRP by the Tennessee Valley Authority (TVA) illustrates how robust planning enables risk-aware resource choices and avoids higher-cost, higher-risk supply portfolios. TVA considered five resource strategies and subjected each to extensive scenario analysis. **Figure ES-5** shows how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[14] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio[15] or emphasized new nuclear plant construction. The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy. The TVA analysis is careful and deliberate; analyses by other utilities that reach significantly different thematic conclusions must be scrutinized carefully to examine whether the costs and risks of all resources have been properly evaluated.

Figure ES-5

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK



Updating traditional practices will require effort and commitment from regulators and regulatory staff. Is it worth it? This report identifies numerous benefits from practicing "risk-aware regulation":

- **Consumer benefits** from improved regulatory decision-making and risk management, leading to greater utility investment in lower-cost, lower-risk resources;
- **Utility benefits** in the form of a more stable, predictable business environment that enhances long-term planning capabilities;
- **Investor benefits** resulting from lowered threats to utility cost recovery, which simultaneously preserves utility credit quality and capital markets access and keeps financing costs low, benefitting all stakeholders;
- **Systemic regulatory benefits** resulting from expanded transparency, inclusion and sophistication in the regulatory process, thereby strengthening stakeholder relationships, building trust and improving policy maker understanding of energy options—all of which enhances regulators' ability to do their jobs;
- **Broad societal benefits** flowing from a cleaner, smarter, more resilient electricity system.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term.

14 Tennessee Valley Authority (TVA), *TVA's Environmental and Energy Future* (Knoxville, TN: Tennessee Valley Authority, 2011), 161, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

15 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent) (TVA, 73).

CONCLUSIONS & RECOMMENDATIONS

- **The U.S. electric utility industry has entered what may be the most uncertain, complex and risky period in its history.** Several forces will conspire to make the next two decades especially challenging for electric utilities: large investment requirements, stricter environmental controls, decarbonization, changing energy economics, rapidly evolving technologies and reduced load growth. Succeeding with this investment challenge—building a smarter, cleaner, more resilient electric system for the 21st century at the lowest overall risk and cost—will require commitment, collaboration, shared understanding, transparency and accountability among regulators, policy makers, utilities and a wide range of stakeholders.

- **These challenges call for new utility business models and new regulatory paradigms.** Both regulators and utilities need to evolve beyond historical practice. Today's electricity industry presents challenges that traditional electricity regulation did not anticipate and cannot fully address. Similarly, the constraints and opportunities for electric utilities going forward are very different than they were a century ago, when the traditional (and still predominant) utility business model emerged.

  Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, ratemaking and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and utility shareholders. This means promoting an inclusive and transparent planning process, diversifying resource portfolios, supporting forward-looking regulatory policies, continually reevaluating their strategies and shaking off "we've always done it that way" thinking.

- **Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process.** One of the most important duties of a 21st century electricity regulator is to understand, examine and manage the risk inherent in utility resource selection. Existing regulatory tools often lack the sophistication to do this effectively.

  Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources.

  Regulators practicing "risk-aware regulation" must exhaust lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. Regulators should immediately notify regulated utilities of their intention to address risks more directly, and then begin explicitly to include risk assessment in all decisions about utility resource acquisition.

- **More than ever, ratepayer funding is a precious resource.** Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in resource investment decisions and could pose a threat to utility earnings.

- **Risk shifting is not risk minimization.** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.
- **Investors are more vulnerable than in the past.** During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than six percent of utilities' overall capital investment, costing shareholders roughly $19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers. Investors should closely monitor utilities' large capex decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.
- **Cost recovery mechanisms currently viewed positively by the investment community including the rating agencies could pose longer-term threats to utilities and investors.** Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility's regulatory and business environment in the long run.
- **Some successful strategies for managing risk are already evident.** Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios.

- **Regulators have important tools at their disposal.** Careful planning is the regulator's primary tool for risk mitigation. This is true for regulators in both vertically-integrated and restructured electricity markets. Effective resource planning considers a wide variety of resources, examines possible future scenarios and considers the risk of various portfolios. Regulators should employ transparent ratemaking practices that reveal and do not obscure the level of risk inherent in a resource choice; they should selectively apply financial and physical hedges, including long-term contracts. Importantly, they must hold utilities accountable for their obligations and commitments.

1. CONTEXT:

INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY & RISK

U.S. ELECTRIC UTILITIES ARE FACING A SET OF CHALLENGES UNPARALLELED IN THE INDUSTRY'S HISTORY, PROVIDING MANY REASONS TO CONCLUDE THAT THE TRADITIONAL PRACTICES OF UTILITIES AND THEIR REGULATORS MUST BE UPDATED TO ADD A SHARPER FOCUS ON RISK MANAGEMENT IN THE REGULATORY PROCESS.

Consider the forces acting on the electricity sector in 2012:

- an aging generation fleet;
- infrastructure upgrades to the distribution system;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[16]
- disruptive changes in the economics of coal and natural gas;
- new transmission investments;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- tight credit in a difficult economy and substantially weakened industry financial metrics and credit ratings.

In a recent book, Peter Fox-Penner, principal and chairman emeritus of the Brattle Group, concluded that the sum of these forces is leading to a "second revolution" in the electric power industry.[17] Navigant Consulting has observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[18]

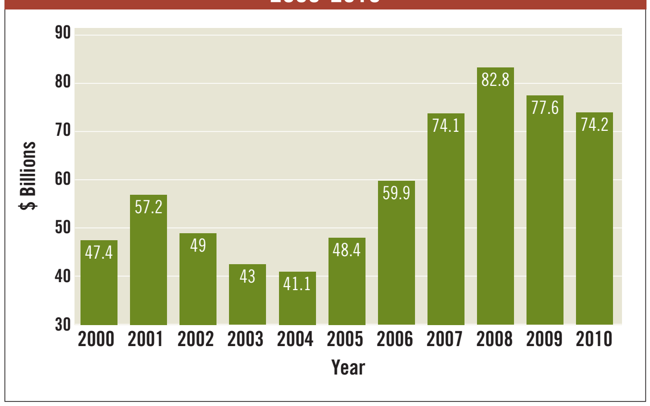
THE INVESTMENT CHALLENGE

The United States electric utility industry is a network of approximately 3,300 investor-owned utilities (IOUs), cooperative associations and government entities. In addition, about 1,100 independent power producers sell power to utilities, either under contract or through auction markets. The net asset value of the plant in service for all U.S. electric utilities in 2010 was about $1.1 trillion, broken down as $765 billion for IOUs, about $200 billion for municipal (publicly-owned) utilities (or "munis"), and $112 billion for rural electric cooperatives (or "co-ops").[19]

IOUs therefore constitute the largest segment of the U.S. electric power industry, serving roughly 70 percent of the U.S. population. **Figure 1** illustrates IOUs' capital expenditures from 2000-2010 and captures the start of the current "build cycle," beginning in 2006.[20] Between 2006 and 2010, capital spending by IOUs—for generation, transmission and distribution systems—was about 10 percent of the firms' net plant in service.

Figure 1

CAPITAL EXPENDITURES BY U.S. INVESTOR-OWNED UTILITIES, 2000-2010



16 See footnote 2.

17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The "first revolution" was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

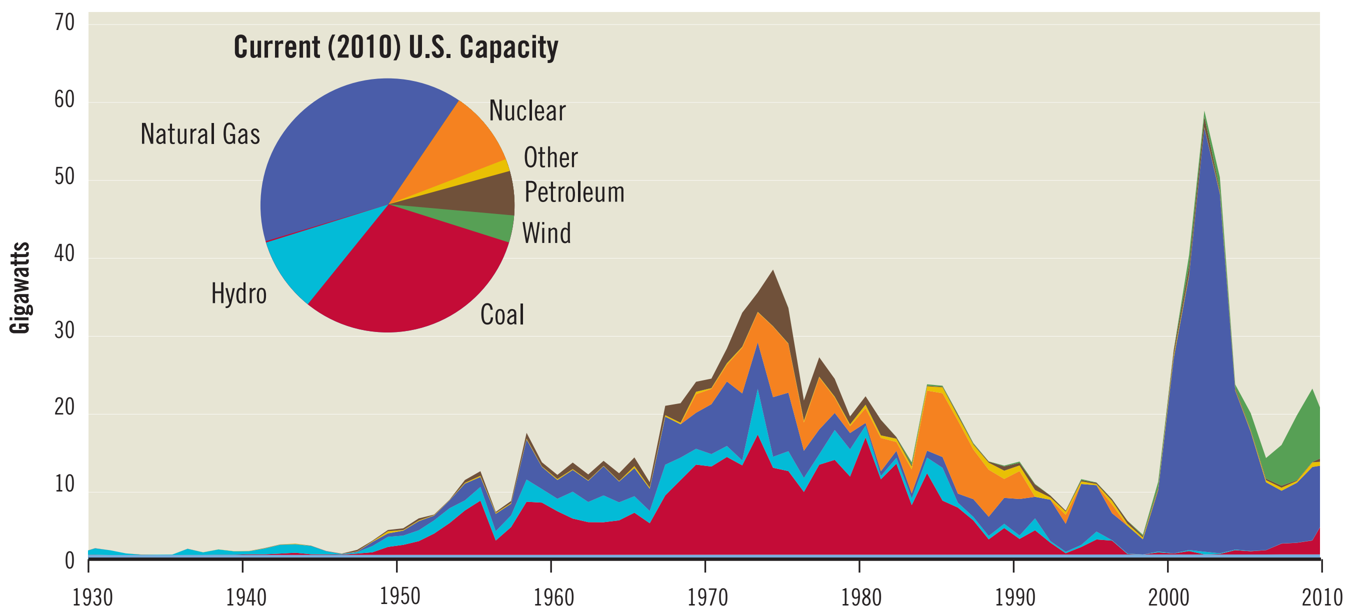
18 Small and Frantzis, *The 21st Century Electric Utility*, 28.

19 See U.S. Energy Information Administration, "Electric Power Industry Overview 2007," http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html; National Rural Electric Cooperative Association, "Co-op Facts and Figures," http://www.nreca.coop/members/Co-opFacts/Pages/default.aspx; Edison Electric Institute, "Industry Data," http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Note that these numbers do not include investment by non-utility generators.

20 Edison Electric Institute, *2010 Financial Review*, 18.

Figure 2

U.S. ELECTRIC GENERATING CAPACITY BY IN-SERVICE YEAR AND FUEL TYPE



In 2008, the Brattle Group projected that the collected U.S. electric utility industry—IOUs, munis, and co-ops—would need to invest capital at historic levels between 2010 and 2030 to replace aging infrastructure, deploy new technologies, and meet future consumer needs and government policy requirements. In all, Brattle predicted that total industry-wide capital expenditures from 2010 to 2030 would amount to between $1.5 trillion and $2.0 trillion.[21] Assuming that the U.S. implements a policy limiting greenhouse gas emissions, the collected utility industry may be expected to invest at roughly the same elevated annual rate as in the 2006-2010 period *each year for 20 years.*

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital.

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital. This growth is considerably faster than the country has seen in many decades.

To understand the seriousness of the investment challenge facing the industry, consider the age of the existing generation fleet. About 70 percent of U.S. electric generating capacity is at least 30 years old (**Figure 2**).[22] Much of this older capacity is coal-based generation subject to significant pressure from the Clean Air Act (CAA) because of its emissions of traditional pollutants such as nitrous oxides, sulfur dioxides, mercury and particulates. Moreover, following a landmark Supreme Court ruling, the U.S. Environmental Protection Agency (EPA) is beginning to regulate as pollutants carbon dioxide and other greenhouse gas emissions from power plants.[23] These regulations will put even more pressure on coal plants, which produce the most greenhouse gas emissions of any electric generating technology. The nuclear capacity of the U.S., approximately 100,000 megawatts, was built mainly in the 1970s and 80s, with original licenses of 40 years. While the lives of many nuclear plants are being extended with additional investment, some of these plants will face retirement within the next two decades.

21 Chupka et al., *Transforming America's Power Industry*, vi. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. The range in Brattle's investment estimate is due to its varying assumptions about U.S. climate policy enactment.

22 U.S. Energy Information Administration, "Today in Energy: Age of electric power generators varies widely," June 16, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

23 U.S. Supreme Court, *Massachusetts v. Environmental Protection Agency,* 549 U.S. 497 (2007), http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf.

Figure 3

PROJECTED GENERATION CAPEX BY REGION

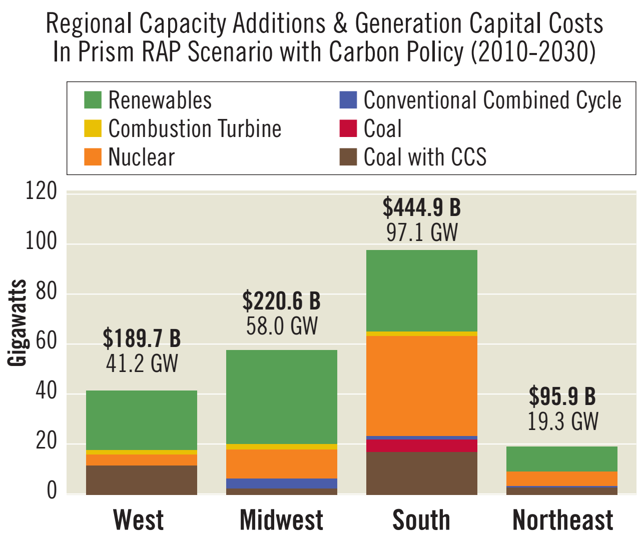


Figure 4

PROJECTED CAPACITY ADDITIONS BY STATE & AS A PERCENTAGE OF 2010 GENERATING CAPACITY

State	Predicted Capacity Additions (MW), 2010-2030[25]	Predicted Additions as a Percentage of 2010 Generating Capacity[26]
Texas	23,400	22%
Florida	12,200	21%
Illinois	11,000	25%
Ohio	8,500	26%
Pennsylvania	6,300	14%
New York	5,400	14%
Colorado	2,500	18%

Figure 3 shows the Brattle Group's investment projections for new generating capacity for different U.S. regions,[24] while **Figure 4** predicts capacity additions for selected U.S. states. Importantly, the Brattle Group noted that some of this investment in new power plants could be avoided if regulators and utilities pursued maximum levels of energy efficiency.

DRIVERS OF UTILITY INVESTMENT

Technological change, market pressures and policy imperatives are driving these historic levels of utility investment. As we will see, these same forces are interacting to create unprecedented uncertainty, risk and complexity for utilities and regulators.

Here are eight factors driving the large investment requirements:

1. **THE NEED TO REPLACE AGING GENERATING UNITS.** As mentioned earlier, the average U.S. generating plant is more than 30 years old. Many plants, including base load coal and nuclear plants, are reaching the end of their lives, necessitating either life-extending investments or replacement.

2. **ENVIRONMENTAL REQUIREMENTS.** Today's Clean Air Act (CAA) traces its lineage to a series of federal laws dating back to 1955. Until recent years, the CAA has enjoyed broad bipartisan support as it steadily tightened controls on emissions from U.S. electric power plants. These actions were taken to achieve science-based health improvements for people and the human habitat. While the current set of EPA rules enforcing the CAA has elicited political resistance, it is unlikely that the five-decade long movement in the United States to reduce acid rain, smog, ground ozone, particulates and mercury, among other toxic pollutants, will be derailed. Owners of many fossil-fueled plants will be forced to decide whether to make significant capital investments to clean up emissions and manage available water, or shutter the plants. Since the capacity is needed to serve consumers' demand for power (or "load"), these clean air and clean water policies will stimulate the need for new construction.

24 Chupka et al., *Transforming America's Power Industry*, x. Brattle's Prism RAP Scenario "assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's [Electric Power Research Institute] Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP [realistically achievable potential] EE/DR programs" (ibid., vi). Brattle used EPRI's original Prism analysis, published in September 2007; that document and subsequent updates are available online at http://my.epri.com/portal/server.pt?open=512&objID=216&&PageID=229721&mode=2.

25 State capacity addition predictions are based on Brattle's regional projections and assume that new capital expenditures will be made in proportion to existing investment levels.

26 State generating capacity data: U.S. Energy Information Administration, "State Electricity Profiles," January 30, 2012, http://www.eia.gov/electricity/state/. Percentage is rounded to the nearest whole number.

3 **NEW TRANSMISSION LINES AND UPGRADES.** Utility investment in transmission facilities slowed significantly from 1975 to 1998.[27] In recent years, especially after the creation of deregulated generation markets in about half of the U.S., it has become clear that the transmission deficit will have to be filled. Adding to the need for more transmission investment is the construction of wind, solar and geothermal generation resources, far from customers in areas with little or no existing generation or transmission. Regional transmission planning groups have formed across the country to coordinate the expected push for new transmission capacity.

4 **NETWORK MODERNIZATION/SMART GRID.** The internet is coming to the electric power industry. From synchrophasors on the transmission system (which enable system-wide data measurement in real time), to automated substations; from smart meters, smart appliances, to new customer web-based energy management, investments to "smarten" the grid are fundamentally changing the way electricity is delivered and used. While much of today's activity results from "push" by utilities and regulators, many observers think a "pull" will evolve as consumers engage more fully in managing their own energy use. Additionally, "hardening" the grid against disasters and to enhance national security will drive further investment in distribution infrastructure.

5 **HIGHER PRICES FOR CONSTRUCTION MATERIALS.** Concrete and steel are now priced in a world market. The demand from developing nations is pushing up the cost of materials needed to build power plants and transmission and distribution facilities.

6 **DEMAND GROWTH.** Overall U.S. demand for electric power has slowed with the recent economic recession and is projected to grow minimally in the intermediate term (though some areas, like the U.S. Southwest and Southeast, still project moderate growth). Further, the expected shift toward electric vehicles has the potential to reshape utility load curves, expanding the amount of energy needed in off-peak hours.

7 **DEPLOYING NEW TECHNOLOGIES AND SUPPORTING R&D.** To meet future environmental requirements, especially steep reductions of greenhouse gas emissions by 2050, utilities will need to develop and deploy new technologies at many points in the grid. Either directly or indirectly, utilities will be involved in funding for R&D on carbon capture and storage, new renewable and efficiency technologies, and electric storage.

8 **NATURAL GAS PRICE OUTLOOK.** Natural gas prices have fallen sharply as estimates of U.S. natural gas reserves jumped with the development of drilling technologies that can economically recover gas from shale formations. Longer-term price estimates have also dropped, inducing many utilities to consider replacing aging coal units with new gas-fired units. But in January 2012, the U.S. Energy Information Administration (EIA) sharply revised downward its estimates of U.S. shale gas reserves by more than 40 percent and its estimates of shale gas from the Marcellus region by two-thirds.[28] Reduced long-term supplies and a significant commitment to natural gas for new electric generation could obviously lead to upward pressure on natural gas prices.

FINANCIAL IMPLICATIONS

The credit quality and financial flexibility of U.S. investor-owned electric utilities has declined over the past 40 years, and especially over the last decade (**Figure 5, p. 18**).[29] The industry's financial position today is materially weaker than it was during the last major "build cycle" that was led by vertically-integrated utilities, in the 1970s and 80s. Then the vast majority of IOUs had credit ratings of "A" or higher; today the average credit rating has fallen to "BBB."

While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions.

This erosion of credit quality is mainly the result of intentional decisions by regulators and utility managements, who determined that maintaining an "A" or "AA" balance sheet wasn't worth the additional cost.[30] And while there isn't reason to believe that most utilities' capital markets access will become significantly constrained in the near future, the fact remains that more than a quarter of companies in the sector are now one notch above non-investment grade status (also called "Non-IG," "high yield" or "junk"), and nearly half of the companies in the sector are rated only two or three notches above this threshold.[31] While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions. Dropping below

27 Edison Electric Institute, *EEI Survey of Transmission Investment* (Washington DC: Edison Electric Institute, 2005), 3, http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Survey_Web.pdf.

28 U.S. Energy Information Administration, *AEO2012 Early Release Overview* (Washington DC: U.S. Energy Information Administration, 2012), 9, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf.

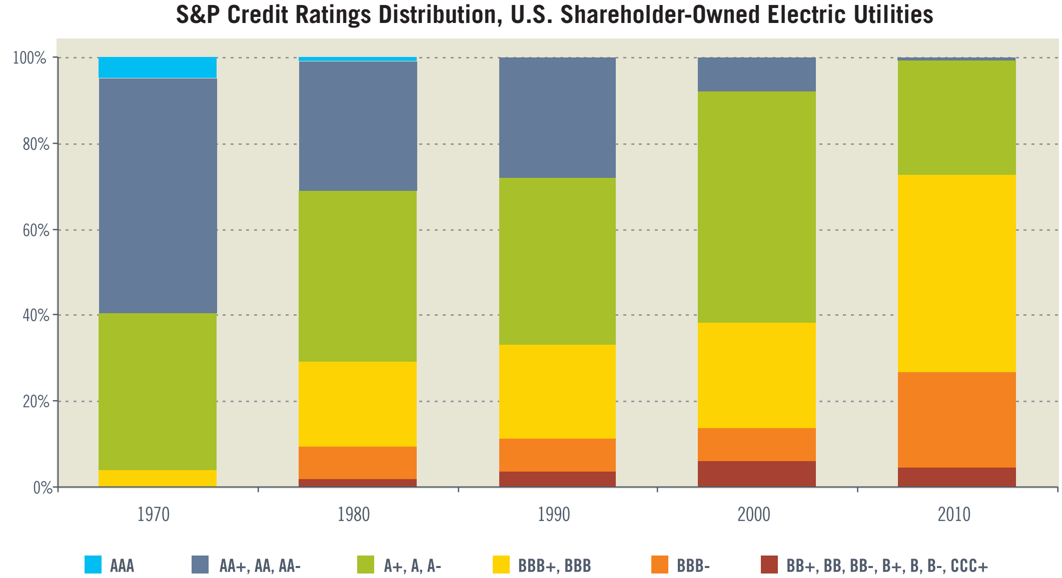
29 Source: Standard & Poor's Ratings Service.

30 The difference in the interest rate on an "A" rated utility and BBB is on average over time rarely more than 100 basis points. By contrast, equity financing typically costs a utility at least 200 basis points more than debt financing.

31 Companies in the sector include IOUs, utility holding companies and non-regulated affiliates.

Figure 5

U.S. ELECTRIC IOUs CREDIT RATINGS HISTORY, 1970 – 2010



investment grade (or "IG") triggers a marked rise in interest rates for debt issuers and a marked drop in demand from institutional investors, who are largely prohibited from investing in junk bonds under the investment criteria set by their boards.

According to a Standard & Poor's analyst, utilities' capital expenditure programs will invariably cause them to become increasingly cash flow negative, pressuring company balance sheets, financial metrics and credit ratings: "In other words, utilities will be entering the capital markets for substantial amounts of both debt and equity to support their infrastructure investments as operating cash flows will not come close to satisfying these infrastructure needs."[32] Specific utilities that S&P has identified as particularly challenged are companies—such as Ameren, Dominion, FirstEnergy, and PPL—that have both regulated and merchant generation businesses and must rely on market pricing to recover environmental capital expenditures for their merchant fleets.[33]

Appendix 1 of this report presents an overview of utility finance.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery.

CUSTOMER IMPACTS

The surge in IOU capital investment will translate directly into higher electric rates paid by consumers. Increased capital investment means higher annual depreciation expenses as firms seek to recover their investment. Greater levels of investment mean higher revenue requirements calculated to yield a return on the investment. And since electric sales may not grow much or at all during the coming two decades, it is likely that unit prices for electricity will rise sharply.

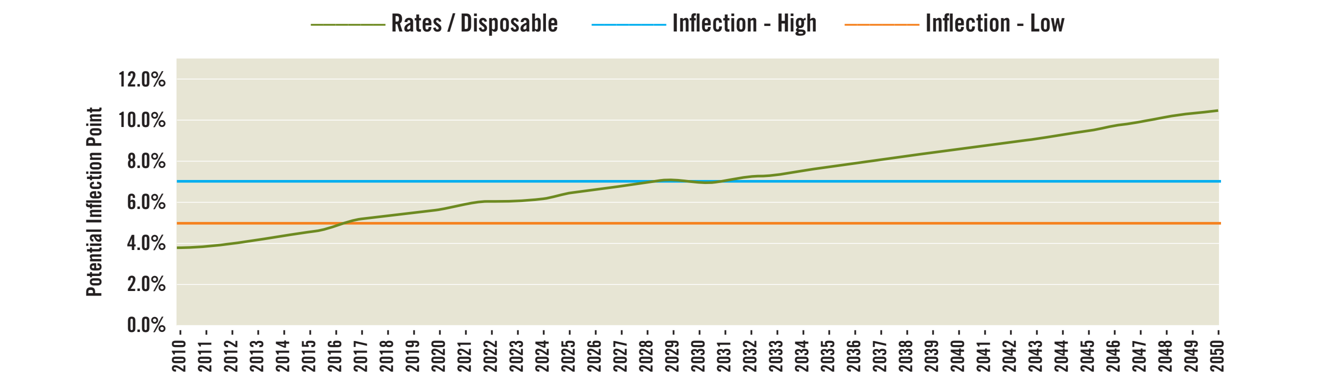
While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery. The rating agency Moody's Investors Service has noted that "consumer tolerance to rising rates is a primary concern"[34] and has identified political and regulatory risks as key longer-term challenges facing the sector.[35]

Further, Moody's anticipates an "inflection point" where consumers revolt as electricity bills consume a greater share of disposable income (**Figure 6, p. 19**),[36] pressuring legislators and regulators to withhold from utilities the recovery of even prudently incurred expenses.

32 Cortright, "Testimony."
33 Standard & Poor's, *The Top 10 Investor Questions for U.S. Regulated Electric Utilities in 2012* (New York: Standard & Poor's, 2012).
34 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2011).
35 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2010).
36 Moody's, *Special Comment: The 21st Century Electric Utility*, 12.

Figure 6

MOODY'S PROJECTED "INFLECTION POINT" OF CONSUMER INTOLERANCE FOR RISING ELECTRICITY BILLS



Source: Moody's

THE IMPORTANCE OF REGULATORS

With this background, the challenge becomes clear: how to ensure that the large level of capital invested by utilities over the next two decades is deployed wisely? How to give U.S. ratepayers, taxpayers and investors the assurance that $2 trillion will be spent in the best manner possible? There are two parts to the answer: *effective regulators* and the *right incentives for utilities*.

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.[37] It is essential that regulators understand the risks involved in resource selection, correct for the biases facing utility regulation and keep in mind the impact their decisions will have on consumers and society.

Are U.S. regulatory institutions prepared? Consumers, lawmakers and the financial markets are counting on it. The authors are confident that well-informed, focused state regulators are up to the task. But energy regulation in the coming decades will be quite different from much of its history. The 21st century regulator must be willing to look outside the boundaries established by regulatory tradition. Effective regulators must be informed, active, consistent, curious and often courageous.

This report focuses on techniques to address the risk associated with utility resource selection. It provides regulators with some tools needed to understand, identify and minimize the risks inherent in the industry's investment challenge. In short, we hope to help regulators become more "risk-aware."

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.

37 In 2012, the median number of years served by a state regulator was 3.7 years; see Janice A. Beecher, Ph.D., *IPU Research Note: Commissioner Demographics 2012* (East Lansing, MI: Michigan State University, 2012), http://ipu.msu.edu/research/pdfs/IPU-Commissioner-Demographics-2012.pdf.

2. CHALLENGES

TO EFFECTIVE REGULATION

THE CHALLENGE FOR U.S. ELECTRIC UTILITIES IS TO RAISE, SPEND AND RECOVER A HISTORIC AMOUNT OF CAPITAL DURING A PERIOD OF UNPRECEDENTED UNCERTAINTY. THE CHALLENGE FOR STATE REGULATORS IS TO DO EVERYTHING POSSIBLE TO ENSURE THAT UTILITIES' INVESTMENTS ARE MADE WISELY. TO DO THIS EFFECTIVELY, REGULATORS WILL NEED TO BE ESPECIALLY ATTENTIVE TO TWO AREAS: IDENTIFYING AND ADDRESSING RISK, AND OVERCOMING REGULATORY BIASES. THIS SECTION DISCUSSES RISK AND BIAS IN MORE DETAIL.

RISK INHERENT IN UTILITY RESOURCE SELECTION

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Risk accumulates from multiple sources. In mathematical terms:

Risk = $\sum_i \textit{Event}_i \times (\textit{Probability of Event}_i)$

for a situation in which a set of independent events will cause a loss with some probability. In English, this means that risk is the sum of each possible loss times the probability of that loss, assuming the events are independent of each other. If a financial instrument valued at $100 million would be worth $60 million in bankruptcy, and the probability of bankruptcy is 2 percent, then the bankruptcy risk associated with that instrument is said to be ($100 million - $60 million) x 2%, or $800,000. Thus, risk is the *expected value of a potential loss*. There is an obvious tie to insurance premiums; leaving aside transaction costs and the time value of money, an investor would be willing to pay up to $800,000 to insure against the potential bankruptcy loss just described.

Higher risk for a resource or portfolio means a larger expected value of a potential loss. In other words, higher risk means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Uncertainty is similar to risk in that it describes a situation where a deviation from the expected can occur, but it differs in two respects. First, the probability of the unexpected event cannot feasibly be determined with any precision. Consider the potential of much higher costs for natural gas used as a generation resource for an electric utility. Such an outcome is certainly possible (and perhaps even likely, given the potential for an increased rate of construction of new natural gas generation). But the likelihood and scope of such a change would be difficult to assess in terms of mathematical probabilities. Second, unlike risk, uncertainty can result in

The Historical Basis for Utility Regulation

Utilities aren't like other private sector businesses. Their services are essential in today's world, and society expects utilities to set up costly infrastructure networks supported by revenue from electric rates and to serve everyone without discrimination. Because of their special attributes, we say that investor-owned utilities are private companies that are "affected with the public interest." Indeed, this is often the statutory definition of utilities in state law.

Utility infrastructure networks include very long-lived assets. Power plants and transmission lines are designed to last decades; some U.S. transmission facilities are approaching 100 years old. The high cost of market entry makes competition impractical, uneconomic or impossible in many sectors of these markets. And because society requires universal service, it made economic sense to grant monopoly status to the owners of these essential facilities and then to regulate them.

State regulatory utility commissioners began administering a system of oversight for utilities at about the turn of the 20th century, filling a role that had previously been accorded to state legislatures. Regulatory commissions were tasked with creating a stable business environment for investment while assuring that customers would be treated "justly and reasonably" by monopoly utilities. Then as now, consumers wanted good utility services and didn't want to pay too much for them. Rules for accounting were supplemented by regulatory expectations, which were then followed by a body of precedents associated with cost recovery.

Because the sector's complexity and risks have evolved considerably since many regulatory precedents were established, today's regulators are well-advised to "think outside the box" and consider reforming past precedent where appropriate. The last section of this report, "Practicing Risk-Aware Regulation," contains specific ideas and recommendations in this regard.

Figure 7

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

either upside or downside changes. As we will see later, uncertainty should be identified, modeled and treated much like risk when considering utility resource selection. In this report we will focus on risk and the negative aspect of uncertainty, and we will simplify by using the term "risk" to apply to both concepts.

The risks associated with utility resource selection are many and varied and arise from many possible events, as shown in **Figure 7**. There are several ways to classify these risks. One helpful distinction is made between cost-related risks and time-related risks.

Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Construction costs for a project can increase between regulatory approval and project completion. Transmission projects are notorious for this phenomenon due to unexpected obstacles in siting, or to unexpected changes in raw material costs.

Costs can change unexpectedly at any time. For example, a catastrophic equipment failure or the adoption of a new standard for pollution control could present unforeseen costs that a utility may not be willing to pay to keep an asset operating. Planned-for cost recovery can be disrupted by changes in costs for which regulators are unwilling to burden customers, or for other reasons. If an asset becomes obsolete, useless or uneconomic before the end of its predicted economic life, a regulator could find that it is no longer "used and useful" to consumers and remove it from the utility rate base. In these ways, decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Sometimes this risk can manifest itself even between the time a utility makes a decision and the time approval is sought. For example, anticipated load growth may not materialize, so that a planned generation resource is not needed, at least not now.

Time risks also reflect the fact that, for some investments, some essential condition may not occur on a schedule necessary for the investment to be approved and constructed. Consider the dilemma of the developer who wishes to build a low cost wind farm in an area with weak electric transmission. The wind project might require three to four years to build, but the transmission capacity needed to move the power to market may take five to seven years to build—*if* the development goes relatively smoothly. Investors may forego the wind farm due to uncertainty that the transmission will be built, while at the same time the transmission might not be built because, without the wind farm, it is simply too speculative.

Decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

In the power sector, investments are so long-lived that time can be measured in generations. Generally speaking, regulators consider it most fair if the generation of consumers that uses an asset is the same one that pays for the asset. Burdening customers before or after an asset is useful is often seen as violating the "just and reasonable" standard. The challenge to the utility, therefore, is to fit cost recovery for an asset into the timeframe in which it is used. Otherwise, the utility may bear the risk that regulators or consumers push back on assuming responsibility for the cost.

Perspectives on Risk

Risk means different things to different stakeholders. For example:

- For **utility management**, risks are a threat to the company's financial health, its growth, even its existence; a threat to the firm's competitiveness, to the firm's image, and to its legacy.
- For **customers**, risk threatens household disposable income, the profitability of businesses, the quality of energy service, and even comfort and entertainment.
- **Investors** focus on the safety of the income, value of the investment (stock or bond holders), or performance of the contract (counterparties). In addition, investors value utility investments based on their expectations of performance.
- **Employees** are uniquely connected to the utility. Their employment, safety and welfare is directly related to their company's ability to succeed and to avoid financial catastrophes.
- **Society generally** has expectations for utilities ranging from providing reliable, universal service, to aiding in economic development, to achieving satisfactory environmental and safety performance. Risk threatens these goals.

ELECTRICITY MARKET STRUCTURE AND RISK

Much has changed since non-utility power producers led the most recent industry build cycle in the 1990s and early 2000s. To begin with, financial reforms from Sarbanes-Oxley legislation, other "Enron fixes," and now the Dodd-Frank Act have substantially changed some accounting and corporate disclosure rules. Investors now receive more detailed and transparent information about asset value (which is "marked to market") and possible risks in contracts with counter-parties.

These changes, which protect investors, may have the associated effect of discouraging investments if cumulative risks are judged to be outsized for the circumstances. This is especially relevant for markets served by the competitive generation system that now supplies power to about half of U.S. consumers. It is unclear whether independent generators have the tolerance to take on large, risky investments; experience indicates that there is a frontier beyond which these companies and their backers may not go.

This dynamic could raise important questions for regulators in restructured markets, who need to be aware of the degree to which investment options might be limited by these concerns. In vertically-integrated markets, regulators' concern should be not to expose utilities, customers and investors to undue risk by approving large projects that informed market players would not pursue in the absence of regulatory approval.

One potentially risky but necessary area of investment is in low carbon generation technologies. The U.S. power sector, which has embraced generation competition, is required to develop these technologies. Some promising technologies—including coal-fired generation with carbon capture and storage or sequestration (CCS), advanced nuclear power technologies and offshore wind—have not reached a commercial stage or become available at a commercial price.

Risks requiring special attention are those associated with investments that "bet the company" on their success. Gigawatt-sized investments in any generation technology may trigger this concern, as can a thousand-mile extra high voltage transmission line. Any investment measured in billions of dollars can be proportionately out of scale with what a utility can endure if things go awry. Regulators should avoid a situation where the only choices left are a utility bankruptcy or a waiving of regulatory principles on prudence and cost recovery in order to save the utility, placing a necessary but unreasonable cost burden on consumers.

REGULATORS, RATING AGENCIES AND RISK

Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms. As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. This may give companies and investors a false sense of security and induce them to take on excessive risk. In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.

Given the influence of regulators on the operations and finances of IOUs, ratings agencies and investors closely monitor the interactions between utility executives and regulators. Constructive relationships between management and regulators are viewed as credit positive; less-than-constructive relationships, which can result from regulators' concerns about the competence or integrity of utility management, are seen as a credit negative and harmful to a utility's business prospects.

Analysts define a constructive regulatory climate as one that is likely to produce stable, predictable regulatory outcomes over time. "Constructive," then, refers as much to the quality of regulatory decision-making as it does to the financial reward for the utility. Regulatory decisions that seem overly generous to utilities could raise red flags for analysts, since these decisions could draw fire and destabilize the regulatory climate. Analysts may also become concerned about the credit quality of a company if the state regulatory process appears to become unduly politicized.

While they intend only to observe and report, ratings agencies can exert a discipline on utility managements not unlike that imposed more formally by regulators. For example, ratings agencies can reveal to utility managements the range of factors they should consider when formulating an investment strategy, thereby influencing utility decision-making. Both regulators and ratings agencies set long-term standards and expectations that utilities are wise to mind; both can provide utilities with feedback that would discourage one investment strategy or another.

Since ratings reflect the issuer's perceived ability to repay investors over time, the ratings agencies look negatively on anything that increases event risk. The larger an undertaking (e.g., large conventional generation investments), the larger the fallout if an unforeseen event undermines the project. The pressure to maintain healthy financial metrics may, in practice, serve to limit utilities' capital expenditure programs and thus the size of rate increase requests to regulators.

TAKEAWAYS ABOUT RISK

Here are three observations about risk that should be stressed:

1. RISK CANNOT BE ELIMINATED—BUT IT CAN BE MANAGED AND MINIMIZED. Because risks are defined in terms of probabilities, it is (by definition) probable that some risk materializes. In utility resource selection, this means that risk will eventually find its way into costs and then into prices for electricity. Thus, taking on risk is inevitable, and risk will translate into consumer or investor costs—into dollars—sooner or later. Later in this report, we present recommendations to enable regulators to practice their trade in a "risk-aware" manner—incorporating the notion of risk into every decision.

2. IT IS UNLIKELY THAT CONSUMERS WILL BEAR THE FULL COST OF POOR UTILITY RESOURCE INVESTMENT DECISIONS. Put another way, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investments than in years past. In utility regulation, risk is shared between investors and customers in a complex manner. To begin, the existence of regulation and a group of customers who depend on utility service is what makes investors willing to lend utilities massive amounts of money (since most customers have few if any choices and must pay for utility service). But the actualization of a risk, a loss, may be apportioned by regulators to utility investors, utility consumers, or a combination of both. The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to make ratepayers pay for the full cost of utility mistakes.

3. IGNORING RISK IS NOT A VIABLE STRATEGY. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. In utility regulation, perhaps more so than anywhere else, making no choice is itself making a choice. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

NATURAL BIASES AFFECTING UTILITY REGULATION

Notwithstanding economic theory, we must admit that utilities are not perfectly rational actors and that their regulation is not textbook-perfect, either. Utility regulation faces several built-in biases, which one can think of as headwinds against which regulation must sail. For example, under traditional cost-of-service regulation, a considerable portion of fixed costs (i.e., investment in rate base) is often recovered through variable charges to consumers. In this circumstance, one would expect utilities to have a bias toward promoting sales of the product once rates are established—even if increasing sales might result in increased financial, reliability, or environmental risks and mean the inefficient use of consumer dollars.

Here are five natural biases that effective utility regulation must acknowledge and correct for:

- **Information asymmetry.** Regulators are typically handicapped by not having the same information that is available to the regulated companies. This becomes especially significant for the utility planning process, where regulators need to know the full range of potential options for meeting electric demand in future periods. In the same vein, regulators do not normally have adequate information to assess market risks. These are the considerations of CFOs and boardrooms, and not routinely available to regulators. Finally, operating utilities often exist in a holding company with affiliated interests. The regulator does not have insight into the interplay of the parent and subsidiary company—the role played by the utility in the context of the holding company.
- **The Averch-Johnson effect.** A second bias is recognized in the economic literature as the tendency of utilities to over-invest in capital compared to labor. This effect is known by the name of the economists who first identified the bias: the Averch-Johnson effect (or simply the "A-J effect"). The short form of the A-J effect is that permitting

a rate of return on investment will have the predictable effect of encouraging more investment than is optimal. This can manifest itself in the "build versus buy" decisions of integrated utilities and is often cited as a reason utilities might "gold plate" their assets. This effect can also be observed in the "invest versus conserve" decisions that utilities face. Under traditional regulatory rules, most utilities do not naturally turn toward energy efficiency investment, even though such investments are usually least cost for customers.

- **The throughput incentive.** A third bias that can be observed with utilities is the bias for throughput—selling more electricity. This is undoubtedly grounded in the vision that most utilities have traditionally had for themselves: providers of electricity. Importantly, the regulatory apparatus in most states reinforces the motivation to sell more electricity: a utility's short-run profitability and its ability to cover fixed costs is directly related to the utility's level of sales. The price of the marginal unit of electricity often recovers more than marginal costs, so utilities make more if they sell more. Only in recent years has the concept of an energy services provider developed in which the utility provides or enables energy efficiency, in addition to providing energy.
- **Rent-seeking.** A fourth bias often cited in the literature is "rent seeking," where the regulated company attempts to use the regulatory or legislative processes as a means of increasing profitability (rather than improving its own operational efficiency or competitive position). This can occur when firms use law or regulation to protect markets that should be open to competition, or to impose costs on competitors.
- **"Bigger-is-better"** syndrome. Another bias, related to the Averch-Johnson effect, might be called the "bigger is better" syndrome. Utilities tend to be conservative organizations that rely on past strategies and practices. Making large investments in relatively few resources had been the rule through the 1980s and into the 1990s. Because of this history, utilities may not naturally support smaller scale resources, distributed resources or programmatic solutions to energy efficiency.[38]

Regulation can compensate for these biases by conducting clear-headed analysis, using processes that bring forth a maximum of relevant information and, very importantly, identifying the risk that these biases might introduce into utility resource acquisition. In the next section, we will take a close look at the many risks facing generation resource investments, which involve some of the most important and complex decisions that regulators and utilities make.

38 To be fair, smaller scale resources can add transaction and labor expenses for which the utility would not earn a return under traditional cost of service regulation, which helps to explain limited utility interest in these options.

3. COSTS AND RISKS

OF NEW GENERATION RESOURCES

THE CAPITAL INVESTED BY U.S. ELECTRIC UTILITIES TO BUILD A SMARTER, CLEANER, MORE RESILIENT ELECTRICITY SYSTEM OVER THE NEXT TWO DECADES WILL GO TOWARDS UTILITIES' GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS.

In this section we'll take an in-depth look at costs and risks of new generation resources, for several reasons:

- Generation investment will be the largest share of utility spending in the current build cycle; this is where the largest amount of consumer and investor dollars will be at stake.
- Today's decisions about generation investment can shape tomorrow's decisions about transmission and distribution investment (by reducing or increasing the need for such investment).
- Technology breakthroughs—in energy storage, grid management, solar PV, and elsewhere—could radically transform our need for base load power within the useful lives of power plants being built today.
- Generation resources are among utilities' most visible and controversial investments and can be a lightning rod for protest and media attention, intensifying scrutiny on regulatory and corporate decision-makers.
- The industry's familiarity with traditional generating resources (e.g., large centralized fossil and nuclear plants) and relative lack of familiarity with newer alternatives (e.g., demand-side resources such as energy efficiency and demand response, or smaller, modular generating resources like combined heat and power) could lead regulators and utilities to underestimate risks associated with traditional resources and overestimate risks of newer resources.
- Finally, investment decisions about generation resources (especially nuclear power) during the last major build cycle that was led by vertically-integrated utilities, in the 1970s and 80s, destroyed tens of billions of dollars of consumer and shareholder wealth.

For these and other reasons, a comprehensive look at risks and costs of today's generation resources is in order.

While this discussion is most directly applicable to regulators (and other parties) in vertically-integrated states where electric utilities build and own generation, it also has implications for regulators (and other parties) in restructured states. For example, regulators in some restructured states (e.g., Massachusetts) are beginning to allow transmission and distribution (T&D) utilities to own generation again, specifically small-scale renewable generation to comprise a certain percentage of a larger renewable portfolio standard. Further, enhanced appreciation of the risks embedded in T&D utilities' supply portfolios could induce regulators to require utilities to employ best practices with regard to portfolio management, thereby reducing the risks and costs of providing electricity service.[39] Finally, regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as the following discussion makes clear, are utilities' lowest-cost and lowest-risk resources.

PAST AS PROLOGUE: FINANCIAL DISASTERS FROM THE 1980s

The last time regulated U.S. utilities played a central role in building significant new generating capacity additions as part of a major industry-wide build cycle was during the 1970s and 80s.[40] At the time the industry's overwhelming focus was on nuclear power, with the Nuclear Regulatory Commission (NRC) licensing construction of more than 200 nuclear power plants.

The difficulties the industry experienced were numerous and well-known: more than 100 nuclear plants abandoned in various stages of development;[41] cost overruns so high that the average plant cost three times initial estimates;[42] and total "above-market" costs to society—ratepayers, taxpayers and shareholders—estimated at more than $200 billion.[43]

39 For a discussion of energy portfolio management, see William Steinhurst et al., *Energy Portfolio Management: Tools & Resources for State Public Utility Commissions* (Cambridge, MA: Synapse Energy Economics, 2006), http://www.naruc.org/Grants/Documents/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

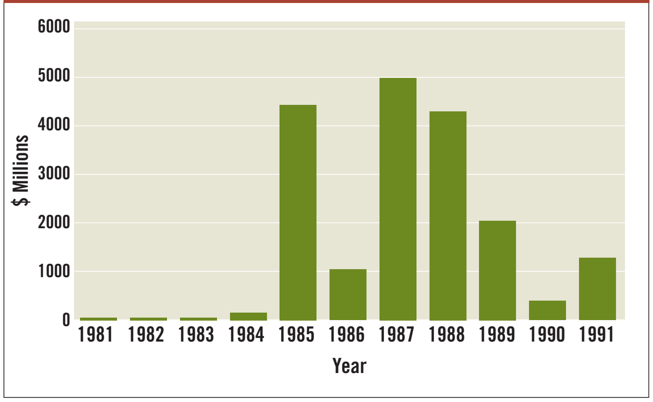
41 Peter Bradford, *Subsidy Without Borders: The Case of Nuclear Power* (Cambridge, MA: Harvard Electricity Policy Group, 2008).

42 U.S. Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs* (Washington, DC: U.S. Energy Information Administration, 1986).

43 Huntowski, Fisher and Patterson, *Embrace Electric Competition*, 18. Estimate is expressed in 2007 dollars.

Figure 8

U.S. UTILITY GENERATION INVESTMENT DISALLOWED BY REGULATORS, 1981-1991



While the vast majority of these losses were borne by ratepayers and taxpayers, utility shareholders were not immune. Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities (**Figure 8**).[44] During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame.

To put this in perspective for the current build cycle, consider **Figure 9**. For illustrative purposes, it shows what disallowances of 6.6 percent of IOU investment would look like for shareholders in the current build cycle, using Brattle's investment projections for the 2010-2030 timeframe referenced earlier. The table also shows what shareholder losses would be if regulators were to disallow investment a) at half the rate of disallowances of the 1981-91 period; and b) at twice the rate of that period.[45]

Figure 9

ILLUSTRATIVE PROSPECTIVE SHAREHOLDER LOSSES DUE TO REGULATORY DISALLOWANCES, 2010-2030

Disallowance Ratio	Investment	
	$1.5 T	$2.0 T
3.3%	$34.6 B	$46.2 B
6.6%	$69.3 B	$92.4 B
13.2%	$138.6 B	$184.8 B

Obviously, the *average* disallowance ratio from the 1980s doesn't tell the full story. A few companies bore the brunt of the regulatory action. One of the largest disallowances was for New York's Nine Mile Point 2 nuclear plant, where the $2 billion-plus disallowance was estimated to be 34 percent of the project's original capital cost.[46] When Niagara Mohawk, the lead utility partner in the project, wrote down its investment in the project by $890 million, Standard & Poor's lowered the company's credit rating by two notches, from A- to BBB. Thus the risk inherent in building the Nine Mile Point 2 plant was visited on investors, who experienced a loss of value of at least $890 million, and consumers, who faced potentially higher interest rates going forward. A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

Another large disallowance was levied on Pacific Gas and Electric for the Diablo Canyon nuclear station in California. The disallowance took the form of a "performance plan" that set consumers' price for power at a level that was independent of the plant's actual cost. In its 1988 decision, the California Public Utilities Commission approved a settlement whereby PG&E would collect $2 billion less, calculated on a net present value basis, than it had spent to build the plant. The CPUC's decision to approve the disallowance was controversial, and some felt it didn't go far enough. The California Division of Ratepayer Advocate (DRA) calculated PG&E's actual "imprudence" to be $4.4 billion (about 75 percent of the plant's final cost), and concluded that customers ultimately paid $2.4 billion more than was prudent for the plant—even after the $2 billion disallowance.[47]

A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

These two large disallowances could be joined by many other examples where unrecognized risk "came home to roost." Consider the destruction of shareholder equity that occurred when Public Service of New Hampshire (PSNH) declared bankruptcy in 1988 because of the burden of its investment in the Seabrook Nuclear Unit, or the enormous debt burden placed on ratepayers by the failure of New York's largest utility, Long Island Lighting Company (LILCO), or the 1983 multi-billion dollar municipal bond default by the Washington Public Power Supply System (WPPSS) when it abandoned attempts to construct five nuclear units in southeast Washington.

44 Lyon and Mayo, *Regulatory opportunism*, 632.

45 Assumes 70 percent of investment is by regulated entities. Illustrative estimates do not include potential losses for utility customers or taxpayers.

46 Fred I. Denny and David E. Dismukes, *Power System Operations and Electricity Markets* (Boca Raton, FL: CRC Press, 2002), 17.

47 The California Public Utilities Commission Decision is available on the Lexis database at: 1988 Cal. PUC LEXIS 886; 30 CPUC2d 189; 99 P.U.R.4th 141, December 19, 1988; As Amended June 16, 1989.

All of these financial disasters share four important traits:

- a weak planning process;
- the attempted development of large, capital-intensive central generation resources;
- utility management's rigid commitment to a preferred investment course; and
- regulators' unwillingness to burden consumers with costs judged retrospectively to be imprudent.

We do not propose to assess blame twenty-five years later, but we do question whether the regulatory process correctly interpreted the risk involved in the construction of these plants—whether, with all risks accounted for, these plants should actually have been part of a "least cost" portfolio for these utilities. The lesson is clear: both investors and customers would have been much better served if the regulators had practiced "risk-aware" regulation.

Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.

CHARACTERISTICS OF GENERATION RESOURCES

A utility's generation portfolio typically consists of a variety of resources that vary in their costs and operating characteristics. Some plants have high capital costs but lower fuel costs (e.g., coal and nuclear) or no fuel costs (e.g., hydro, wind, solar PV). Other plants have lower capital costs but relatively high fuel and operating costs (e.g., natural gas combined cycle). Some plants are designed to operate continuously in "base load" mode, while others are designed to run relatively few hours each year, ramping up and down quickly.

Some resources (including demand response) offer firm capacity in the sense that they are able to be called upon, or "dispatchable," in real time, while other resources are not dispatchable or under the control of the utility or system operator (e.g., some hydro, wind, solar PV).

Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

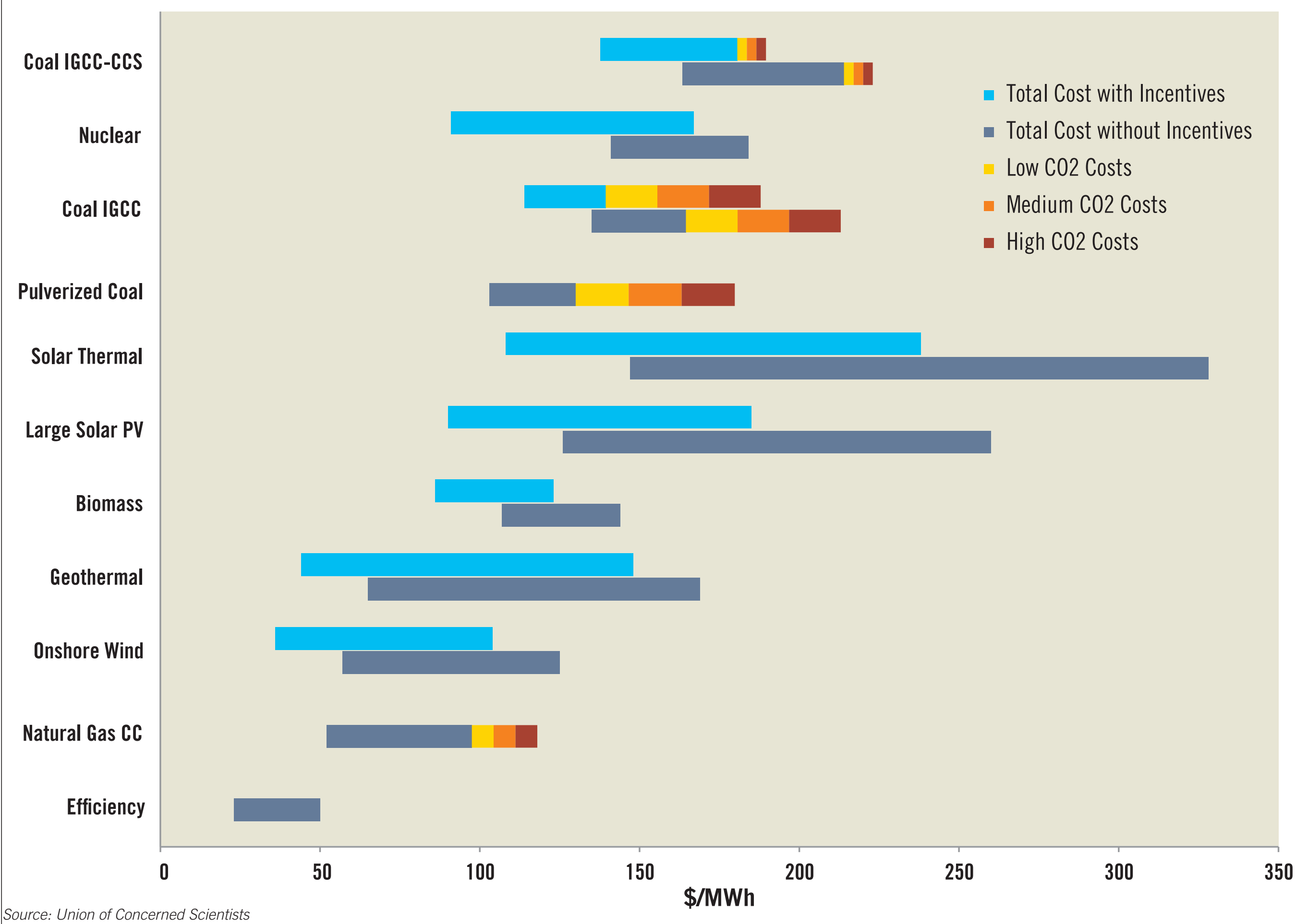
None of these characteristics *per se* makes a resource more or less useful in a utility's resource "stack." Some utility systems operate with a large percentage of generation provided by base load plants. Other systems employ a large amount of non-dispatchable generation like wind energy, combined with flexible gas or hydro generation to supply capacity. What's important is how the resources combine in a portfolio.

For example, in 2008 the Colorado Public Utilities Commission determined that an optimum portfolio for Xcel Energy would include a large amount of wind production, mixed in with natural gas generation and older base load coal plants. Xcel has learned how to manage its system to accommodate large amounts of wind production even though wind is not a "firm" resource. In October 2011, Xcel Energy set a world record for wind energy deployment by an integrated utility: in a one-hour period, wind power provided 55.6 percent of the energy delivered on the Xcel Colorado system.[48]

48 Mark Jaffe, "Xcel Sets World Record for Wind Power Generation," *The Denver Post*, November 15, 2011, http://www.denverpost.com/breakingnews/ci_19342896.

Figure 10

LEVELIZED COST OF ELECTRICITY FOR VARIOUS GENERATION TECHNOLOGIES IN 2015 (2010$)



Source: Union of Concerned Scientists

DECIPHERING THE LEVELIZED COST OF ELECTRICITY

Despite the differences between generation resources, it's possible to summarize and compare their respective costs in a single numerical measure. This quantity, called the "levelized cost of electricity," or "LCOE," indicates the cost per megawatt-hour for electricity over the life of the plant. LCOE encompasses all expected costs over the life of the plant, including costs for capital, operations and maintenance (O&M) and fuel.

Three of the most commonly cited sources of LCOE data for new U.S. generation resources are the Energy Information Administration (EIA); the California Energy Commission (CEC); and the international advisory and asset management firm Lazard. In a recent publication, the Union of Concerned Scientists (UCS) combined the largely consensus LCOE estimates from these three sources to produce a graphic illustrating LCOE for a range of resources (**Figure 10**).[49] The data is expressed in dollars per megawatt-hour, in 2010 dollars, for resources assumed to be online in 2015.

The UCS chart allows a visual comparison of the relative LCOEs among the selected group of resources. The width of the bars in the chart reflects the uncertainty in the cost of each resource, including the variation in LCOE that can result in different regions of the U.S. The UCS report also shows the resources' relative exposure to future carbon costs—not surprisingly, coal-based generation would be most heavily affected—as well as their dependence on federal investment incentives.[50]

49 Freese et al., *A Risky Proposition*, 41.

50 The UCS report estimated incentives by including tax credits for a wide range of technologies and both tax credits and loan guarantees for new nuclear plants. Tax credits currently available for wind and biomass were assumed to be extended to 2015 for illustrative purposes.

We'll use these LCOE estimates to illustrate the combined attributes of cost and risk for new generation resources. To do this, we'll take the midpoint of the cost ranges (including a medium estimate for costs associated with carbon controls) for each technology and create an indicative ranking of these resources by highest to lowest LCOE (**Figure 11**).

For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind and photovoltaic power, the actual costs in 2015 are likely to be lower than the estimate due to recent sharp cost declines and the 2011 market prices for these resources.[51]

Several observations are in order about this ranking. First, some of the technologies show a very wide range of costs, notably geothermal, large solar PV and solar thermal. The breadth of the range represents, in part, the variation in performance of the technology in various regions of the country. In other words, the underlying cost estimates incorporate geographically varying geothermal and solar energy levels.

Second, the estimates used in this ranking are sensitive to many assumptions; the use of the midpoint to represent a technology in this ranking may suggest greater precision than is warranted. For this reason, the ranking shown in Figure 11 should be considered an indicative ranking. Two resources that are adjacent in the ranking might switch places under modest changes in the assumptions. That said, the ranking is useful for visualizing the relative magnitude of costs associated with various technologies and how those are projected to compare in the next few years.

Finally, the LCOE ranking tells only part of the story. The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it. In the next section we will examine these same technologies and estimate the composite risk to consumers, the utility and its investors for each technology.

The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

Figure 11

RELATIVE COST RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)

Solar Thermal
Solar—Distributed*
Large Solar PV*
Coal IGCC-CCS
Solar Thermal w/ incentives
Coal IGCC
Nuclear*
Coal IGCC-CCS w/ incentives
Coal IGCC w/ incentives
Large Solar PV w/ incentives*
Pulverized Coal
Nuclear w/ incentives*
Biomass
Geothermal
Biomass w/ incentives
Natural Gas CC-CCS
Geothermal w/ incentives
Onshore Wind*
Natural Gas CC
Onshore Wind w/ incentives*
Biomass Co-firing
Efficiency

LOWEST LEVELIZED COST OF ELECTRICITY (2010)

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

51 For example, in November 2011, the Colorado Public Utilities Commission approved a 25-year power purchase agreement between Xcel Energy and NextEra for wind generation in Colorado. The contract price is $27.50 per MWh in the first year and escalates at 2 percent per year. The levelized cost of the contract over 25 years is $34.75, less than the assumed lowest price for onshore wind with incentives in 2015 in Figure 10. For details, see Colorado PUC Decision No. C11-1291, available at http://www.colorado.gov/dora/cse-google-static/?q=C11-1291&cof=FORIDA10&ie=UTF-8&sa=Search. For more on wind power cost reductions, see Ryan Wiser et al., "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects" (presentation materials funded by the Wind and Water Power Program of the U.S. Department of Energy, February 2012), http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf. For information on recent PV cost reductions, see Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight Report: 2011 Year in Review: Executive Summary* (Washington, DC: Solar Energy Industries Association, 2012), 10-11, http://www.seia.org/cs/research/solarinsight.

RELATIVE RISK OF NEW GENERATION RESOURCES

In Figure 7 on p. 21, we identified many of the time-related and cost-related risks that attach to a decision to choose a utility resource. We will now examine various generation resource choices in light of these risks, grouping those examples of risk into seven categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

These risks are discussed in detail below.

Intermittency vs. Risk

Certain resources, like wind, solar, and some hydropower facilities, are termed "intermittent" or "variable" resources. This means that while the power produced by them can be well characterized over the long run and successfully predicted in the short run, it cannot be precisely scheduled or dispatched. For that reason, variable resources are assigned a relatively low "capacity value" compared to base load power plants. The operating characteristics of any resource affect how it is integrated into a generation portfolio, and how its output is balanced by other resources.

This characteristic, intermittency, should not be confused with the concept of risk. Recall that risk is the expected value of a loss. In this case, the "loss" would be that the plant does not perform as expected—that it does not fulfill its role in a generation portfolio. For wind or solar resources, intermittency is expected and is accommodated in the portfolio design. Thus, while individual wind towers might be highly intermittent, and a collection of towers in a wind farm less so, a wind farm can also be termed highly reliable and present low risk because it will likely operate as predicted.

CONSTRUCTION COST RISK

Construction cost risk is the risk that the cost to develop, finance and construct a generation resource will exceed initial estimates. This risk depends on several factors, including the size of the project, the complexity of the technology, and the experience with developing and building such projects. The riskiest generation resources in this regard are technologies still in development, such as advanced nuclear and fossil-fired plants with carbon capture and storage. Construction cost risk is especially relevant for nuclear plants due to their very large size and long lead times. (Recall that a large percentage of the disallowed investment during the 1980s was for nuclear plants.) Transmission line projects are also subject to cost overruns, as are other large generation facilities. For example, Duke Energy's Edwardsport coal gasification power plant in Indiana has experienced billion-dollar cost overruns that have raised the installed cost to $5,593 per kilowatt, up from an original estimate of $3,364 per kilowatt.[52]

The lowest construction cost risk attaches to energy efficiency and to renewable technologies with known cost histories. In the middle will be technologies that are variations on known technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

FUEL AND OPERATING COST RISK

Fossil-fueled and nuclear generation is assigned "medium risk" for the potential upward trend of costs and the volatility familiar to natural gas supply.[53] Efficiency and renewable generation have no "fuel" risk. Biomass is assigned "medium" in this risk category because of a degree of uncertainty about the cost and environmental assessment of that fuel. Plants with higher labor components (e.g., nuclear, coal) have higher exposure to inflationary impacts on labor costs.

Analysts are split on the question of the future price of natural gas. The large reserves in shale formations and the ability to tap those resources economically through new applications of technology suggest that the price of natural gas may remain relatively low for the future and that the traditional volatility of natural gas prices will dampen. On the other hand, there remains substantial uncertainty about the quantity of economically recoverable shale gas reserves and controversy about the industrial processes used to develop these unconventional resources.

52 John Russell, "Duke CEO about plant: 'Yes, it's expensive,'" *The Indianapolis Star,* October 27, 2011, http://www.indystar.com/article/20111027/NEWS14/110270360/star-watch-duke-energy-Edwardsport-iurc.

53 Research conducted by the late economist Shimon Awerbuch demonstrated that adding renewable resources to traditional fossil portfolios lowers portfolio risk by hedging fuel cost variability; see Awerbuch, "How Wind and Other Renewables Really Affect Generating Costs: A Portfolio Risk Approach" (presentation at the European Forum for Renewable Energy Resources, Edinburgh, UK, October 7, 2005), http://www.eufores.org/uploads/media/Awerbuch-edinburgh_risk-portoflios-security-distver-Oct-20051.pdf. For a discussion of using renewable energy to reduce fuel price risk and environmental compliance in utility portfolios, see Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2005), http://eetd.lbl.gov/ea/ems/reports/58450.pdf.

There is also significant debate at the moment about the future price of coal. Some sources of low-sulfur coal are being depleted, raising the specter of higher production costs. Further, U.S. exports to China and other countries suggest upward pressure on this traditionally stable-priced fuel.

In this report we have steered a middle course on natural gas and coal prices, assuming that the risk of future surprises in natural gas and coal availability and price to be "medium." This is consistent with the price projection for these two generation fuels used by the Energy Information Administration in its current long-term energy forecast. In its most recent estimate, EIA assumes a real annual price escalation between 2010 and 2035 of about 1.3 percent for coal at the mine mouth and 1.8 percent for natural gas at the wellhead.[54]

Finally, operating cost risk includes the potential for catastrophic failure of a resource. This is especially significant for systems that could be taken down by a single point of failure. Contrast the impact of the failure of a turbine at a large steam plant as compared to the failure of a single turbine at a 100-turbine wind farm. The first failure causes the unavailability of 100 percent of capacity; the second failure causes a 1 percent reduction in capacity availability. Even if the probabilities of the failures are widely different, the size of the loss (risk) has cost implications for the reserve capacity (insurance) that must be carried on the large plant. Small outages are much easier to accommodate than large ones.[55]

Intermittency should not be confused with the concept of risk… For wind or solar resources, intermittency is expected and is accommodated in the portfolio design.

Modularity and unit size are also relevant to demand-side resources that are, by their nature, diverse. Designing good energy efficiency programs involves scrutinizing individual measures for the potential that they may not deliver the expected level of energy savings over time. This estimate can be factored into expectations for overall program performance so that the resource performs as expected. Since it would be extremely unlikely for individual measure failures to produce a catastrophic loss of the resource, diverse demand-side resources are, on this measure, less risky than large generation-side resources.

NEW REGULATION RISK

Nuclear generation is famously affected by accidents and the resulting changes in regulations. The recent accident at Fukushima in Japan illustrates how even a seemingly settled technology—in this case, GE boiling water reactors—can receive increased regulatory scrutiny. Further, the future of nuclear waste disposal remains unclear, even though the current fleet of reactors is buffered by reserves that are designed to cover this contingency. For these reasons, we consider nuclear power to face a high risk of future regulations.

Carbon sequestration and storage (CCS) appears to be subject to similar elevated risks regarding liability. The ownership and responsibility for long-term maintenance and monitoring for carbon storage sites will remain an unknown risk factor in coal and gas generation proposed with CCS.

Other thermal generation (e.g., biomass and geothermal) are also given a "medium" probability due to potential air regulations and land use regulations. Finally, as noted above, the price of natural gas, especially shale gas produced using "fracking" techniques, is at risk of future environmental regulation.

CARBON PRICE RISK

Fossil generation without CCS has a high risk of being affected by future carbon emission limits. Although there is no political agreement on the policy mechanism to place a cost on carbon (i.e., tax or cap), the authors expect that the scientific evidence of climate change will eventually compel concerted federal action and that greenhouse gas emissions will be costly for fossil-fueled generation. Energy efficiency, renewable and nuclear resources have no exposure to carbon risk, at least with respect to emissions at the plant.[56]

A more complex story appears when we consider the emissions related to the full life-cycle of generation technologies and their fuel cycles. For example, nuclear fuel production is an energy-intensive and carbon-intensive process on its own. As the cost of emitting carbon rises, we should expect the cost of nuclear fuel to rise.

Similar comments could apply to renewable facilities that require raw materials and fabrication that will, at least in the near-term, involve carbon-emitting production processes. However, these effects are second-order and much smaller than the carbon impact of primary generation fuels or motive power (e.g., coal, gas, wind, sun, nuclear reactions). The exposure of biomass to carbon constraints will depend on the eventual interpretation of carbon offsets and life-cycle analyses. For that reason, biomass and co-firing with biomass is assigned a non-zero risk of "low."

54 U.S. Energy Information Administration, *AEO2012 Early Release Overview*, 12-13.

55 This discussion refers to the ***availability factor*** of a resource; the ***capacity factor*** of a resource is a different issue, with implications for generation system design and operation.

56 For a discussion of how larger amounts of energy efficiency in a utility portfolio can reduce risk associated with carbon regulation, see Ryan Wiser, Amol Phadke and Charles Goldman, *Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West*, Paper 20 (Washington DC: U.S. Department of Energy Publications, 2008), http://digitalcommons.unl.edu/usdoepub/20.

"Retire or Retrofit" Decisions for Coal-Fired Plants

In this report, we've stressed how risk-aware regulation can improve the outcomes of utility selection of new resources. But many regulators will be focusing on existing power plants during the next few years. A key question facing the industry is whether to close coal plants in the face of new and future EPA regulations, or spend money on control systems to clean up some of the plant emissions and keep them running.

States and utilities are just coming to grips with these sorts of decisions. In 2010, Colorado implemented the new Clean Air Clean Jobs Act, under which the Colorado PUC examined Xcel Energy's entire coal fleet. The Colorado Commission entered a single decision addressing the fate of ten coal units. Some were closed, some were retrofitted with pollution controls, and others were converted to burn natural gas. Elsewhere, Progress Energy Carolinas moved decisively to address the same issue with eleven coal units in North Carolina.

We expect that three types of coal plants will emerge in these analyses: plants that should obviously be closed; newer coal plants that should be retrofitted and continue to run; and "plants in the middle." Decisions about these plants in the middle will require regulators to assess the risk of future fuel prices, customer growth, environmental regulations, capital and variable costs for replacement capacity, etc. In short, state commissions will be asked to assess the risks of various paths forward for the plants for which the economics are subject to debate.

The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see "Utilizing Robust Planning Processes" on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. At the end, regulators should enter a decision that addresses all of the relevant risks.

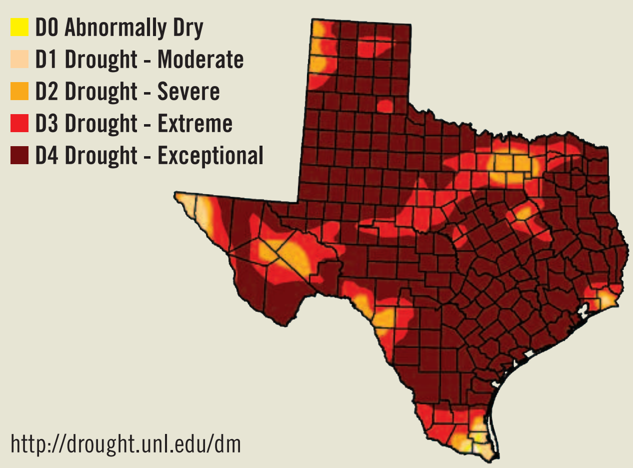
WATER CONSTRAINT RISK

Electric power generation—specifically the cooling of power plants—consumes about 40 percent of all U.S. freshwater withdrawals.[57] The availability and cost of water required for electricity generation will vary with geography but attaches to all of the thermal resources.[58] The recent promulgation by the EPA of the "once-through" cooling rule illustrates the impact that federal regulation can have on thermal facilities; one estimate predicts that more than 400 generating plants providing 27 percent of the nation's generating capacity may need to install costly cooling towers to minimize impacts on water resources.[59] One potential approach, especially for solar thermal, is the use of air-cooling, which significantly lowers water use at a moderate cost to efficiency. Non-thermal generation and energy efficiency have no exposure to this category of risk.

Water emerged as a significant issue for the U.S. electric power sector in 2011. A survey of more than 700 U.S. utility leaders by Black & Veatch indicated "water management was rated as the business issue that could have the greatest impact on the utility industry."[60] Texas suffered from record drought in 2011 at the same time that it experienced all-time highs in electricity demand. **Figure 12** depicts widespread "exceptional drought" conditions in Texas on August 2, 2011,[61] the day before the Electric Reliability Council of Texas (ERCOT) experienced record-breaking peak demand. ERCOT managed to avoid rolling blackouts but warned that continued drought and lack of sufficient cooling water could lead to generation outages totaling "several thousand megawatts."[62]

Figure 12

DROUGHT CONDITIONS IN TEXAS, AUGUST 2, 2011



57 J.F. Kenny et al., "Estimated use of water in the United States in 2005," *U.S. Geological Survey Circular 1344* (Reston, VA: U.S. Geological Survey, 2009), http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

58 For a discussion of freshwater use by U.S. power plants, see Kristen Averyt et al., *Freshwater Use by U.S. Power Plants* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf.

59 Bernstein Research, *U.S. Utilities: Coal-Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* (New York: Bernstein Research, 2010), 69.

60 "U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, Place Emphasis on Growing Nexus of Water and Energy Challenge," Black & Veatch press release, June 13, 2011, http://www.bv.com/wcm/press_release/06132011_9417.aspx.

61 National Drought Mitigation Center, "U.S. Drought Monitor: Texas," August 2, 2011, http://droughtmonitor.unl.edu/archive/20110802/pdfs/TX_dm_110802.pdf.

62 Samantha Bryant, "ERCOT examines grid management during high heat, drought conditions," *Community Impact Newspaper*, October 14, 2011, http://impactnews.com/articles/ercot-examines-grid-management-during-high-heat,-drought-conditions.

In addition to drought, water rights could be an issue for electricity generators in Texas (and elsewhere).[63] The North American Electric Reliability Corporation (NERC) points out that in an extreme scenario, up to 9,000 MW of Texas' generation capacity—over 10 percent of ERCOT's total installed capacity—could be at risk of curtailment if generators' water rights were recalled.[64]

CAPITAL SHOCK RISK

This risk is generally proportional to the size of the capital outlay and the time required for construction of a generating unit. Simply put, the larger the capital outlay and the longer that cost recovery is uncertain, the higher the risk to investors. In this regard, nuclear installations and large new coal facilities with CCS face the highest risk. Smaller, more modular additions to capacity and especially resources that are typically acquired through purchase power agreements record less risk. Finally, distributed solar generation, modifications to enable biomass co-firing and efficiency are accorded low exposure to the risk of capital shock.

PLANNING RISK

This risk relates to the possibility that the underlying assumptions justifying the choice of a resource may change, sometimes even before the resource is deployed. This can occur, for example, when electric demand growth is weaker than forecast, which can result in a portion of the capacity of the new resource being excess. In January 2012, lower-than-anticipated electricity demand, combined with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new, $437 million Spiritwood coal-fired power plant immediately upon the plant's completion. The utility will pay an estimated $30 million next year in maintenance and debt service for the idled plant.[65]

Generation projects with a high ratio of fixed costs and long construction lead times are most susceptible to planning risk. This means that the exposure of base load plants is higher than peaking units, and larger capacity units have more exposure than smaller plants.

In addition to macroeconomic factors like recessions, the electric industry of the early 21st century poses four important unknown factors affecting energy planning. These are 1) the rate of adoption of electric vehicles; 2) the pace of energy efficiency and demand response deployment; 3) the rate of growth of customer-owned distributed generation; and 4) progress toward energy storage. These four unknowns affect various resources in different ways.

Electric vehicles could increase peak demand if customers routinely charge their cars after work, during the remaining hours of the afternoon electrical peak. On the other hand, if electric vehicle use is coupled with time-of-use pricing, this new load has the opportunity to provide relatively desirable nighttime energy loads, making wind generation and nuclear generation and underutilized fossil generation more valuable in many parts of the country.

Energy efficiency (EE) and demand response (DR) affect both electricity (kilowatt-hours) and demand (kilowatts). EE and DR programs differ in relatively how much electricity or demand they conserve. Depending on portfolio design, EE and DR may improve or worsen utility load factors, shifting toward more peaking resources and away from base load plants. Changing customer habits and new "behavioral" EE efforts add to the difficulty in forecasting demand over time.

Distributed generation, especially small solar installation, is expanding rapidly, spurred by new financing models that have lowered the capital outlay from consumers. In addition, we may expect commercial and industrial customers to continue to pursue combined heat and power applications, especially if retail electricity rates continue to rise. Both of these trends will have hard-to-predict impacts on aggregate utility demand and the relative value of different generation resources, but also impacts on primary and secondary distribution investment.

Finally, electric storage at reasonable prices would be a proverbial game-changer, increasing the relative value of intermittent resources such as wind and solar. Microgrids with local generation would also be boosted by low-cost battery storage.

63 For a discussion of how water scarcity could impact municipal water and electric utilities and their bondholders, see Sharlene Leurig, *The Ripple Effect: Water Risk in the Municipal Bond Market* (Boston, MA: Ceres, 2010), http://www.ceres.org/resources/reports/water-bonds/at_download/file. For a framework for managing corporate water risk, see Brooke Barton et al., *The Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management* (Boston, MA: Ceres, 2011), http://www.ceres.org/resources/reports/aqua-gauge/at_download/file.

64 North American Electric Reliability Corporation, *Winter Reliability Assessment 2011/2012* (Atlanta, GA: North American Electric Reliability Corporation, 2011), 29, http://www.nerc.com/files/2011WA_Report_FINAL.pdf.

65 David Shaffer, "Brand new power plant is idled by economy," *Minneapolis StarTribune*, January 9, 2012, http://www.startribune.com/business/134647533.html.

Figure 13

RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	High	Low	Medium
Biomass Co-firing	Low	Low	Medium	Low	High	Low	Low
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Low	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium	High
Efficiency	Low	None	Low	None	None	Low	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Large Solar PV	Low	None	Low	None	None	Medium	Low
Large Solar PV w/ incentives	Low	None	Low	None	None	Low	Low
Natural Gas CC	Medium	High	Medium	Medium	Medium	Medium	Medium
Natural Gas CC-CCS	High	Medium	Medium	Low	High	High	Medium
Nuclear	Very High	Medium	High	None	High	Very High	High
Nuclear w/ incentives	Very High	Medium	High	None	High	High	Medium
Onshore Wind	Low	None	Low	None	None	Low	Low
Onshore Wind w/ incentives	Low	None	Low	None	None	None	Low
Pulverized Coal	Medium	Medium	High	Very High	High	Medium	Medium
Solar - Distributed	Low	None	Low	None	None	Low	Low
Solar Thermal	Medium	None	Low	None	High	Medium	Medium
Solar Thermal w/ incentives	Medium	None	Low	None	High	Low	Medium

ESTABLISHING COMPOSITE RISK

In line with the foregoing discussion, the table in **Figure 13** summarizes the degree of exposure of various generation technologies to these seven categories of risk. The technologies listed are taken from UCS's LCOE ranking in Figure 10 on p. 28, plus three more: natural gas combined cycle with CCS, biomass co-firing and distributed solar PV generation. The chart estimates the degree of risk for each resource across seven major categories of risk, with estimates ranging from "None" to "Very High."

Three comments are in order. First, these assignments of relative risk were made by the authors, and while they are informed they are also subjective. As we discuss later, regulators should conduct their own robust examination of the relative costs and risks including those that are unique to their jurisdiction. Second, the assessment of risk for each resource is intended to be relative to each other, and not absolute in a quantitative sense. Third, while there are likely some correlations between these risk categories—resources with low fuel risk will have low carbon price exposure, for example—other variables exhibit substantial independence.

Figure 14

RELATIVE COST RANKING AND RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar—Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Nuclear w/ incentives
Solar Thermal w/ incentives	Coal IGCC
Coal IGCC	Coal IGCC-CCS w/ incentives
Nuclear*	Natural Gas CC-CCS
Coal IGCC-CCS w/ incentives	Biomass
Coal IGCC w/ incentives	Coal IGCC w/ incentives
Large Solar PV w/ incentives*	Natural Gas CC
Pulverized Coal	Biomass w/ incentives
Nuclear w/ incentives*	Geothermal
Biomass	Biomass Co-firing
Geothermal	Geothermal w/ incentives
Biomass w/ incentives	Solar Thermal
Natural Gas CC-CCS	Solar Thermal w/ incentives
Geothermal w/ incentives	Large Solar PV
Onshore Wind*	Large Solar PV w/ incentives
Natural Gas CC	Onshore Wind
Onshore Wind w/ incentives*	Solar—Distributed
Biomass Co-firing	Onshore Wind w/ incentives
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

* *Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The risk ranking shows a clear difference between renewable resources and non-renewable resources. Nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

Figure 15

RELATIVE COST AND RISK RANKINGS OF NEW GENERATION RESOURCES WITHOUT INCENTIVES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar–Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Coal IGCC
Coal IGCC	Natural Gas CC-CCS
Nuclear*	Biomass
Pulverized Coal	Natural Gas CC
Biomass	Geothermal
Geothermal	Biomass Co-firing
Natural Gas CC-CCS	Solar Thermal
Onshore Wind*	Large Solar PV
Natural Gas CC	Onshore Wind
Biomass Co-firing	Solar–Distributed
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

* *Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

To derive a ranking of these resources with respect to risk, we assigned numeric values to the estimated degrees of risk (None=0, Very High=4) and totaled the rating for each resource. The scores were then renormalized so that the score of the highest-risk resource is 100 and the others are adjusted accordingly. The composite relative risk ranking that emerges is shown in **Figure 14**, which, for ease of comparison, we present alongside the relative cost ranking from Figure 11.

The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear difference between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

To illustrate how resources stack up against each other in more general terms, and for simplicity of viewing, **Figure 15** presents those same rankings without information about incentives.

To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring resource is set to 100. The results of the unweighted ranking, together with the two weighted rankings, are shown in **Figure 16**. By inspection, one can see that the rank order changes very little across the three methods, so that the risk ranking in Figure 14 appears to be relatively robust. Once again, we emphasize that these figures are intended to show the relative risk among the resources, not to be absolute measures of risk.[66]

Figure 16

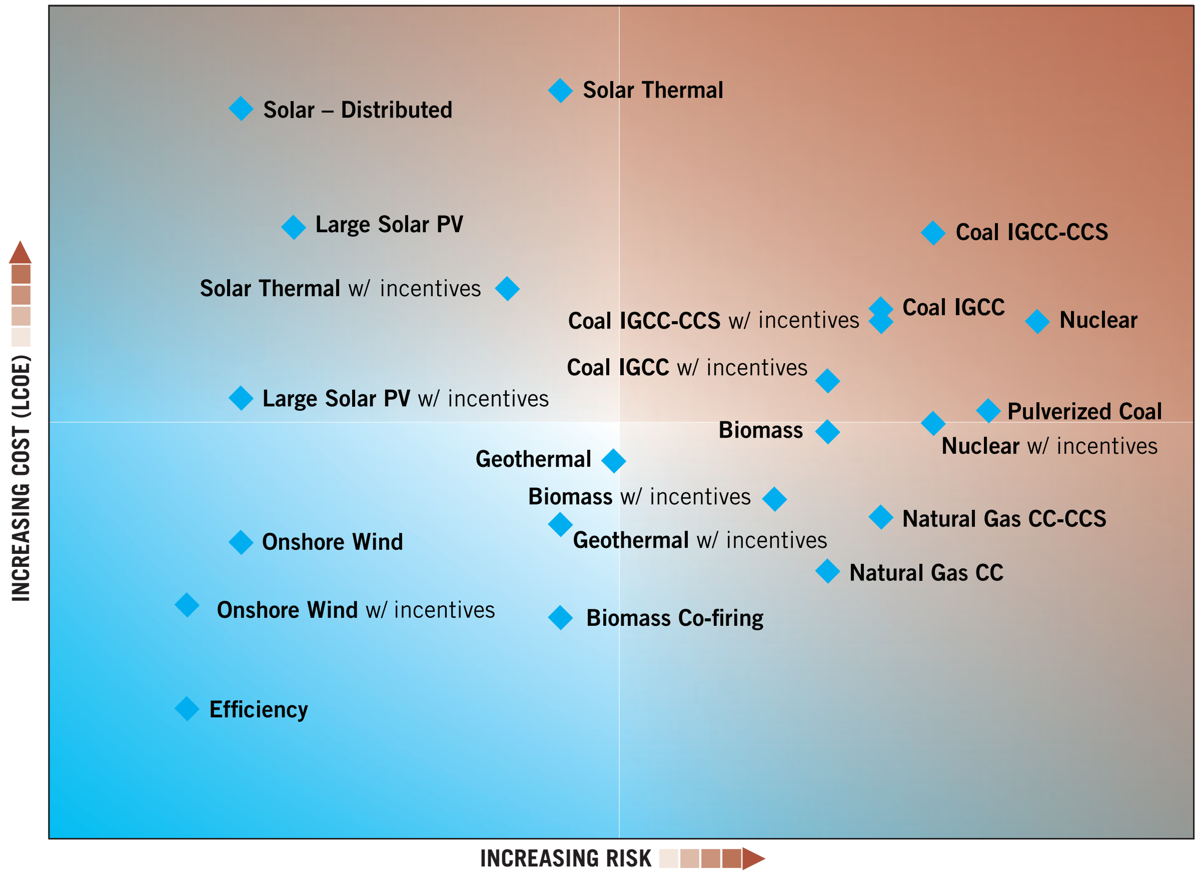
SUMMARY OF RISK SCORES FOR NEW GENERATION RESOURCES

Resource	Composite Score	Environmental Weighted Score	Cost Weighted Score
Biomass	79	79	72
Biomass w/ incentives	74	76	66
Biomass Co-firing	53	57	44
Coal IGCC	84	83	79
Coal IGCC w/ incentives	79	79	72
Coal IGCC-CCS	89	84	87
Coal IGCC-CCS w/ incentives	84	81	80
Efficiency	16	14	16
Geothermal	58	59	52
Geothermal w/ incentives	53	55	46
Large Solar PV	26	22	28
Large Solar PV w/ incentives	21	19	21
Natural Gas CC	79	76	75
Natural Gas CC-CCS	84	79	82
Nuclear	100	91	100
Nuclear w/ incentives	89	83	89
Onshore Wind	21	19	21
Onshore Wind w/ incentives	16	16	15
Pulverized Coal	95	100	82
Solar - Distributed	21	19	21
Solar Thermal	53	52	49
Solar Thermal w/ incentives	47	48	43

66 Dr. Mark Cooper, a longtime utility sector analyst and supporter of consumer interests, recently arrived at similar conclusions about composite risk; see Cooper, *Least-Cost Planning For 21st Century Electricity Supply* (So. Royalton, VT: Vermont Law School, 2011), http://www.vermontlaw.edu/Documents/21st%20Century%20Least%20Cost%20Planning.pdf. Cooper's analysis incorporated not only variations in "risk" and "uncertainty," but also the degrees of "ignorance" and "ambiguity" associated with various resources and the universe of possible future energy scenarios.

Figure 17

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



Finally, we can combine the information in the cost ranking and the risk ranking into a single chart. **Figure 17** shows how resources compare with each other in the two dimensions of cost and risk. The position of a resource along the horizontal axis denotes the relative risk of each resource, while the position on the vertical axis shows the relative cost of the resource.

4. PRACTICING RISK-AWARE REGULATION:

SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

UTILITY REGULATORS ARE FAMILIAR WITH A SCENE THAT PLAYS OUT IN THE HEARING ROOM: DIFFERENT INTERESTS—UTILITIES, INVESTORS, CUSTOMER GROUPS, ENVIRONMENTAL ADVOCATES AND OTHERS—COMPETE TO REDUCE COST AND RISK FOR THEIR SECTOR AT THE EXPENSE OF THE OTHERS. WHILE THE ADVERSARIAL PROCESS MAY MAKE THIS COMPETITION SEEM INEVITABLE, AN OVERLOOKED STRATEGY (THAT USUALLY LACKS AN ADVOCATE) IS TO REDUCE OVERALL RISK TO EVERYONE. MINIMIZING RISK IN THE WAYS DISCUSSED IN THIS SECTION WILL HELP ENSURE THAT ONLY THE UNAVOIDABLE BATTLES COME BEFORE REGULATORS AND THAT THE PUBLIC INTEREST IS SERVED FIRST.

Managing risk intelligently is arguably the main duty of regulators who oversee utility investment. But minimizing risk isn't simply achieving the least cost today. It is part of a strategy to *minimize overall long term costs*. And, as noted earlier, while minimizing risk is a worthy goal, eliminating risk is not an achievable goal. The regulatory process must provide balance for the interests of utilities, consumers and investors in the presence of risk.

One of the goals of "risk-aware" regulation is avoiding the kind of big, costly mistakes in utility resource acquisition that we've seen in the past. But there is another, more affirmative goal: ensuring that society's limited resources (and consumers' limited dollars) are spent wisely. By routinely examining and addressing risk in every major decision, regulators will produce lower cost outcomes in the long run, serving consumers and the public interest in a very fundamental way.

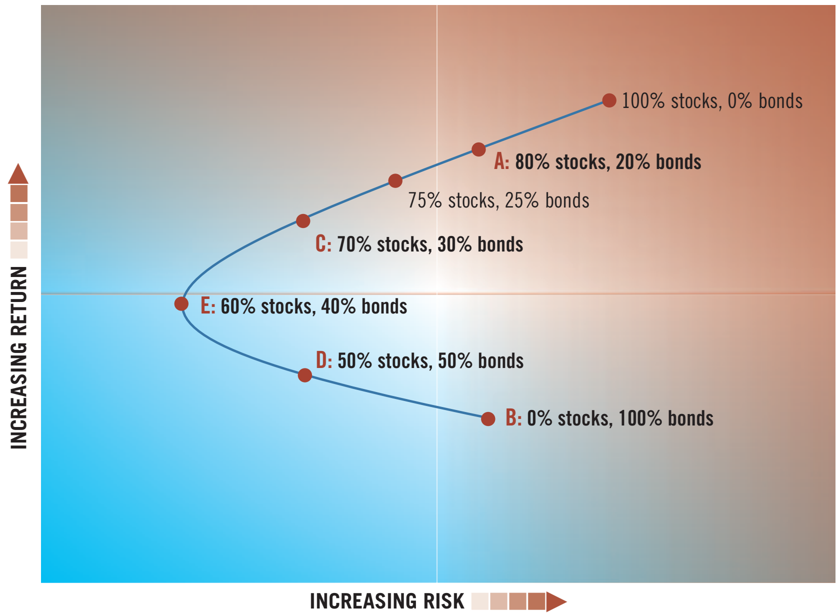
An overlooked strategy (that usually lacks an advocate) is to reduce overall risk to everyone.

WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS CAN EMPLOY TO MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources;
2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment (i.e., generation, transmission, distribution, and demand-side resources like energy efficiency);
3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk;
4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts;
5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments;
6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk;
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate.

Figure 18

RISK/RETURN RELATIONSHIPS AMONG DIFFERENT FINANCIAL PORTFOLIOS
(Illustrative)



We now discuss each of these strategies in more detail.

1. DIVERSIFYING UTILITY SUPPLY PORTFOLIOS

The concept of diversification plays an important role in finance theory. Diversification—investing in different asset classes with different risk profiles—is what allows a pension fund, for example, to reduce portfolio volatility and shield it from outsized swings in value.

Properly chosen elements in a diversified portfolio can increase return for the same level of risk, or, conversely, can reduce risk for a desired level of return. The simple illustration in **Figure 18** allows us to consider the relative risk and return for several portfolios consisting of stocks and bonds. Portfolio A (80% stocks, 20% bonds) provides a higher predicted return than Portfolio B (0% stocks, 100% bonds) even though both portfolios have the same degree of risk. Similarly, Portfolios C and D produce different returns at an identical level of risk that is lower than A and B. Portfolio E (60% stocks, 40% bonds) has the lowest risk, but at the cost of a lower return than Portfolios A and C. The curve in Figure 18 (and the corresponding surface in higher dimensions) is called an *efficient frontier*.

We could complicate the example—by looking at investments in cash, real estate, physical assets, commodities or credit default swaps, say, or by distinguishing between domestic and international stocks, or between bonds of various maturities—but the general lesson would be the same: diversification helps to lower the risk in a portfolio.

Portfolios of utility investments and resource mixes can be analyzed similarly. Instead of return and risk, the analysis would examine cost and risk. And instead of stocks, bonds, real estate and gold, the elements of a utility portfolio are different types of power plants, energy efficiency, purchased power agreements, and distributed generation, among many other potential elements. Each of these elements can be further distinguished by type of fuel, size of plant, length of contract, operating characteristics, degree of utility dispatch control, and so forth. Diversification in a utility portfolio means including various supply and demand-side resources that behave independently from each other in different future scenarios. Later we will consider these attributes in greater detail and discuss what constitutes a diversified utility portfolio.

For a real-world illustration of how diversifying resources lowers cost and risk in utility portfolios, consider the findings of the integrated resource plan recently completed by the Tennessee Valley Authority (TVA).[67] TVA evaluated five resource strategies that were ultimately refined into a single "recommended planning direction" that will guide TVA's resource investments. The resource strategies that TVA considered were:

- **Strategy A:** Limited Change in Current Resource Portfolio[68]
- **Strategy B:** Baseline Plan Resource Portfolio
- **Strategy C:** Diversity Focused Resource Portfolio
- **Strategy D:** Nuclear Focused Resource Portfolio
- **Strategy E:** EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

67 TVA, a corporation owned by the federal government, provides electricity to nine million people in seven southeastern U.S. states; see http://www.tva.com/abouttva/index.htm.

68 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent); see TVA, 73.

Figure 19

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK

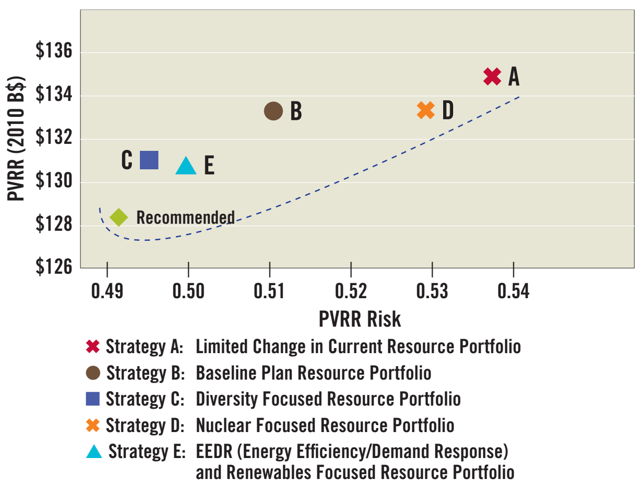


Figure 19 illustrates how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[69] The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy.[70] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio (mostly coal, natural gas and nuclear) or emphasized new nuclear plant construction.

The TVA analysis is very careful and deliberate. To the extent that other analyses reached conclusions thematically different from TVA's, we would question whether the costs and risks of all resources had been properly evaluated. We would also posit that resource investment strategies that differ directionally from TVA's "recommended planning direction" would likely expose customers (and, to some extent, investors) to undue risk. Finally, given the industry's familiarity with traditional resources—and the possibility that regulators and utilities may therefore underestimate the costs and risks of those resources—the TVA example illustrates how careful planning reveals the costs and risks of maintaining resource portfolios that rely heavily on large base load fossil and nuclear plants.

Robust planning processes like TVA's are therefore essential to making risk-aware resource choices. It is to these planning processes that we now turn.

2. UTILIZING ROBUST PLANNING PROCESSES

In the U.S., there are two basic utility market structures: areas where utilities own or control their own generating resources (the "vertically integrated" model), and areas where competitive processes establish wholesale prices (the "organized market" model).

In many vertically integrated markets and in some organized markets, regulators oversee the capital investments of utilities with a process called "integrated resource planning," or IRP. Begun in the 1980s, integrated resource planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all.

Elements of a Robust IRP Process

IRP oversight varies in sophistication, importance and outcomes across the states. Because a robust IRP process is critical to managing risk in a utility, we describe a model IRP process that is designed to produce utility portfolios that are lower risk and lower cost.[71]

These elements characterize a robust IRP process:

- The terms and significance of the IRP approval (including implications for cost recovery) are clearly stated at the outset, often in statute or in a regulatory commission's rules.
- The regulator reviews and approves the modeling inputs used by the utility (e.g., demand and energy forecasts, fuel cost projections, financial assumptions, discount rate, plant costs, fuel costs, energy policy changes, etc.).
- The regulator provides guidance to utility as to the policy goals of the IRP, perhaps shaping the set of portfolios examined.
- Utility analysis produces a set of resource portfolios and analysis of parameters such as future revenue requirement, risk, emissions profile, and sensitivities around input assumptions.
- In a transparent public process, the regulator examines competing portfolios, considering the utility's analysis as well as input from other interested parties.
- Demand resources such as energy efficiency and demand response are accorded equal status with supply resources.
- The regulator approves a plan and the utility is awarded a "presumption of prudence" for actions that are consistent with the approved IRP.
- The utility acquires (i.e., builds or buys) the resources approved in the IRP, possibly through a competitive bidding regime.
- Future challenges to prudence of utility actions are limited to the execution of the IRP, not to the selection of resources approved by the regulator.

69 TVA, 161.

70 In the end, TVA settled on a "recommended planning direction" that calls for demand reductions of 3,600 to 5,100 MW, energy efficiency savings of 11,400 to 14,400 GWh, and renewable generating capacity additions of 1,500 to 2,500 MW by 2020. At the same time, TVA plans to retire 2,400 to 4,700 MW of coal-fired capacity by 2017. See TVA, 156.

71 For an example of an IRP that uses sophisticated risk modeling tools, see PacifiCorp, *2011 Integrated Resource Plan* (Portland, OR: PacifiCorp, 2011), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

IRP: "Accepted" vs. "Approved" Plans

There are two varieties of IRP plans: "accepted plans" and "approved plans." Accepted plans are those where regulators examine the utility's process for developing its proposed plan. This can be a thorough review in which the Commission solicits the opinion of other parties as to whether the utility undertook a transparent, inclusive, and interactive process. If the regulator is convinced, the regulator "accepts" the utility's plan. This allows the utility to proceed but does not include any presumption about the Commission's future judgment concerning the prudence of actions taken under the plan.

With an "approved plan" the regulator undertakes a thorough review of the utility's preferred plan, possibly along with competing IRP plans submitted by other parties. Typically the scrutiny is more detailed and time-consuming in this version of IRP and the regulatory agency is immersed in the details of competing plans. At the end of the process, the regulator "approves" an IRP plan. This approval typically carries with it a presumption that actions taken by the utility consistent with the plan (including its approved amendments) are prudent. Over time, a Commission that approves an IRP plan will typically also examine proposed changes to the plan necessitated by changing circumstances.

In this report, we will focus on the "approved plan" process, although many of our findings apply equally to regulators that employ the "accepted plan" process.

A few of these elements deserve more elaboration.

Significance. The IRP must be meaningful and enforceable; there must be something valuable at stake for the utility and for other parties. From the regulator's point of view, the resource planning process must review a wide variety of portfolio choices whose robustness is tested and compared under different assumptions about the future. From the utilities' perspective, acceptance or approval of an IRP should convey that regulators support the plan's direction, even though specific elements may evolve as circumstances change. If a utility ignores the approved IRP or takes actions that are inconsistent with an IRP without adequate justification, such actions may receive extra scrutiny at the point where the utility seeks cost recovery.

Multiple scenarios. Many different scenarios will allow a utility to meet its future load obligations to customers. These scenarios will differ in cost, risk, generation characteristics, fuel mix, levels of energy efficiency, types of resources, sensitivity to changes in fuel cost, and so forth. While one scenario might apparently be lowest cost under baseline assumptions, it may not be very resilient under different input assumptions. Further, scenarios will differ in levels of risk and how that risk may be apportioned to different parties (e.g., consumers or shareholders). Regulators, with input from interested parties, should specify the types of scenarios that utilities should model and require utilities to perform sensitivity analyses, manipulating key variables.

Consistent, active regulation. An IRP proceeding can be a large, complex undertaking that occurs every two or three years, or even less frequently. It is critical that regulators become active early in the process and stay active throughout. The regulator's involvement should be consistent, even-handed and focused on the big-ticket items. Of course, details matter, but the process is most valuable when it ensures that the utility is headed in the right direction and that its planning avoids major errors. The regulator should then monitor a utility's performance and the utility should be able to trust the regulator's commitment to the path forward laid out in the IRP.

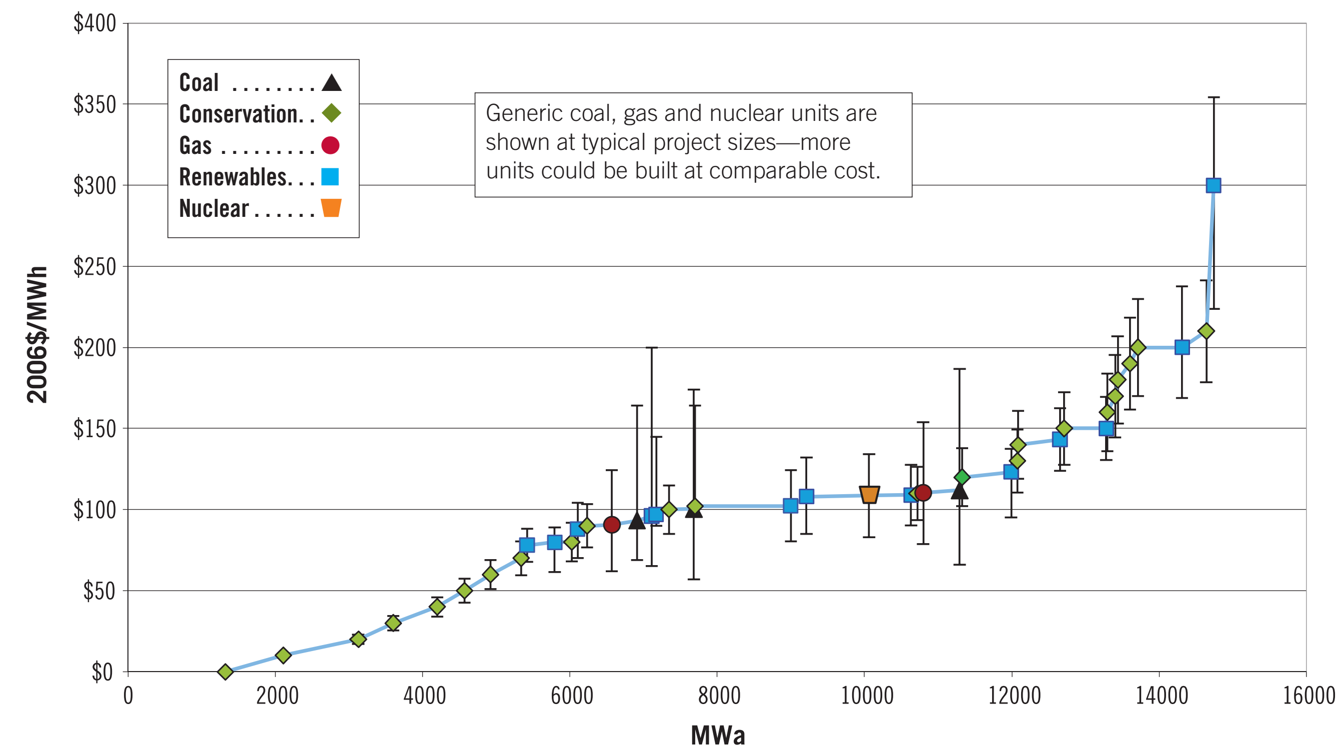
Stakeholder involvement. There are at least two good reasons to encourage broad stakeholder involvement in an IRP process. First, parties besides the utility will bring new ideas, close scrutiny and contrasting analysis to the IRP case, all of which helps the regulator to make an informed, independent decision. Second, effective stakeholder involvement can build support for the IRP that is ultimately approved, heading off collateral attacks and judicial appeals. An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources. Because an IRP decision is something of a political document in addition to being a working plan, regulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources… [R]egulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

Transparency. Regulators must ensure that, to the greatest extent possible, all parties participating in the IRP process have timely access to utility data. Certain data may be competitively sensitive and there is often pressure on the regulator to restrict unduly the access to such data. One possible solution to this challenge is to use an "independent evaluator" who works for the commission, is trusted by all parties and has access to all the data, including proprietary data. The independent evaluator can verify the modeling of the utility and assist the regulator in making an informed decision. The cost of an independent evaluator will be small in comparison to the benefits (or avoided mistakes) that the evaluator will enable. An independent evaluator will also add

Figure 20

PORTFOLIO ANALYSIS ON ONE PAGE
How Energy Efficiency Can Substitute for Generation Resources



credibility to the regulators' decision. In any event, the integrity of the IRP process will depend on regulators' ability to craft processes that are trusted to produce unbiased results.

Competitive bidding. A successful IRP will lower risk in the design of a utility resource portfolio. After the planning process, utilities begin acquiring approved resources. Some states have found it beneficial to require the utility to undertake competitive bidding for all resources acquired by a utility pursuant to an IRP. If the utility will build the resource itself, the regulator may require the utility to join the bidding process or commit to a cap on the construction cost of the asset.[72]

Role of Energy Efficiency. A robust IRP process will fully consider the appropriate levels of energy efficiency, including demand response and load management, that a utility should undertake. Properly viewed and planned for, energy efficiency can be considered as equivalent to a generation resource. Regulators in some states list projected energy efficiency savings on the "loads and resources table" of the utility, adjacent to base load and peaking power plants. In Colorado, energy efficiency is accorded a "reserve margin" in the integrated resource plan, as is done with generation resources.[73]

Since its inception in 1980, the Northwest Power and Conservation Council, which develops and maintains a regional power plan for the Pacific Northwest, has stressed the role of energy efficiency in meeting customers' energy needs. **Figure 20** shows the Council's analysis, demonstrating the elements of a diversified energy portfolio and the role that energy efficiency (or "conservation") can play in substituting for generation resources at various levels of cost.[74]

Appendix 2 contains additional discussion of some of the modeling tools available to regulators.

3. EMPLOYING TRANSPARENT RATEMAKING PRACTICES

Economist Alfred Kahn famously observed that "all regulation is incentive regulation," meaning that any type of economic regulation provides a firm with incentives to make certain choices. Indeed, utility rate regulation's greatest effect may not be its ability to limit prices for consumers in the short run, but rather the incentives it creates for utilities in the longer run.

72 For a discussion of the use of competitive bidding in resource acquisition, see Susan F. Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (Boston, MA: Analysis Group, 2008), http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Competitive_Procurement.pdf.

73 For Xcel Energy in Colorado, energy efficiency is listed on the "loads and resources" table as a resource. As such, it is logical that some fraction of the planned-for load reduction might not materialize. That portion is then assigned the standard resource reserve margin of approximately 15 percent. The planning reserve margin is added to the projected peak load, which must be covered by the combined supply-side and demand-side resources in the table.

74 Tom Eckman, "The 6th Power Plan… and You" (presentation at the Bonneville Power Administration Utility Energy Efficiency Summit, Portland, Ore., March 17, 2010), http://www.bpa.gov/Energy/N/utilities_sharing_ee/Energy_Smart_Awareness/pdf/0A_EESummit_Gen-Session_Public_Power.pdf.

There have been many debates through the years about the incentives that utility cost of service regulation provides. These range from the academic and formal (e.g., the aforementioned Averch-Johnson effect, which says that rate-regulated companies will have an inefficiently high ratio of capital to labor) to the common sense (e.g., price cap regulation can induce companies to reduce quality of service; the throughput incentive discourages electric utilities from pursuing energy efficiency, etc.).

While regulators may want to limit their role to being a substitute for the competition that is missing in certain parts of the electric industry, it is rarely possible to limit regulation's effects that way. The question is usually not how to eliminate stray incentives in decisions, but rather which ones to accept and address.

To contain risk and meet the daunting investment challenges facing the electric industry, regulators should take care to examine exactly what incentives are being conveyed by the details of the regulation they practice. We examine four components of cost of service regulation that affect a utility's perception of risk, and likely affect its preference for different resources.

Current Return on Construction Work in Progress. There is a long-standing debate about whether a utility commission should allow a utility to include in its rates investment in a plant during the years of its construction. Construction Work in Progress, or "CWIP," is universally favored by utility companies and by some regulators, but almost universally opposed by advocates for small and large consumers and by other regulators. CWIP is against the law in some states, mandated by law in others.

The main argument against CWIP is that it requires consumers to pay for a plant often years before it is "used and useful," so that there isn't a careful match between the customers who pay for a plant and those who benefit from it. Proponents of CWIP point out that permitting a current return on CWIP lessens the need for the utility to issue debt and equity, arguably saving customers money, and that CWIP eases in the rate increase, compared to the case where customers feel the full costs of an expensive plant when the plant enters service. Opponents counter by noting that customers typically have a higher discount rate than the utilities' return on rate base, so that delaying a rate hike is preferred by consumers, even if the utility borrows more money to finance the plant until it enters service.

Setting aside the near-religious debate about the equity of permitting CWIP in rate base, there is another relevant consideration. Because CWIP can help utilities secure financing and phase in rate increases, CWIP is often misunderstood as a tool for reducing risk. This is not true.

CWIP, Risk Shifting and Progress Energy's Levy Nuclear Plant

In late 2006, Progress Energy announced plans to build a new nuclear facility in Levy County, Florida, a few months after the state legislature approved construction work in progress (CWIP) customer financing. The site is about 90 miles north of Tampa, near the Gulf of Mexico. In 2009, Progress customers began paying for the Levy plant, which was expected to begin service in 2016 and be built at a cost of $4-6 billion. By the end of 2011, Progress customers had paid $545 million toward Levy's construction expenses.

The Levy plant is now projected to cost up to $22 billion, roughly four times initial estimates, and that number could keep climbing. (In March 2012, Progress Energy's market value as a company was almost $16 billion; the combined market value of Duke Energy and Progress Energy, which are seeking to merge and are pursuing construction of five nuclear facilities between them, is about $44 billion.) Levy's expected in-service date has pushed beyond 2021 and possibly as late as 2027—eighteen years after Progress customers began paying for the plant. Progress has estimated that by 2020, Levy-related expenses could add roughly $50 to the average residential customer's monthly bill.

The Levy plant's development appeared to take a step forward in December 2011 when the Nuclear Regulatory Commission approved its reactor design. But in February 2012, the Florida Public Service Commission approved a settlement agreement allowing Progress to suspend or cancel Levy's construction and recover $350 million from customers through 2017.

It is unclear whether Levy will ever be built. If the plant is canceled, Progress customers will have paid more than $1 billion in rates for no electricity generation, and Florida state law prohibits their recouping any portion of that investment. Such an outcome could help to deteriorate the political and regulatory climate in which Progress operates, which could ultimately impact credit ratings and shareholder value.

CWIP does nothing to actually reduce the risks associated with the projects it helps to finance. Construction cost overruns can and do still occur (see the text box about Progress Energy's Levy County nuclear power plant); O&M costs for the plant can still be unexpectedly high; anticipated customer load may not actually materialize; and so forth. What CWIP does is to reallocate part of the risk from utilities (and would-be bondholders) to customers. CWIP therefore provides utilities with both the incentive and the means to undertake a riskier investment than if CWIP were unavailable.

Regulators must be mindful of the implications of allowing a current return on CWIP, and should consider limiting its use to narrow circumstances and carefully drawn conditions of oversight. Regulators should also pay close attention to how thoroughly utility management has evaluated the risks associated with the projects for which it requests CWIP. Regardless of CWIP's other merits or faults, an important and too-often unacknowledged downside is that it can obscure a project's risk by shifting, not reducing, that risk.

Use of Rider Recovery Mechanisms. Another regulatory issue is the use by utilities of rate "riders" to collect investment or expenses. This practice speeds up cash flow for utilities, providing repayment of capital or expense outlays more rapidly than would traditional cost of service regulation. This allows utilities to begin collecting expenses and recovering capital without needing to capitalize carrying costs or file a rate case. Once again, regulators must consider whether these mechanisms could encourage a utility to undertake a project with higher risk, for the simple reason that cost recovery is assured even before the outlay is made.

Allowing a current return on CWIP, combined with revenue riders, is favored by many debt and equity analysts, who perceive these practices as generally beneficial to investors. And indeed, these mechanisms allow bondholders and stock owners to feel more assured of a return of their investment. And they might marginally reduce the utility's cost of debt and equity. But these mechanisms (which, again, transfer risk rather than actually reducing it) could create a "moral hazard" for utilities to undertake more risky investments. A utility might, for example, proceed with a costly construction project, enabled by CWIP financing, instead of pursuing market purchases of power or energy efficiency projects that would reduce or at least delay the need for the project. If negative financial consequences of such risky decisions extended beyond customers and reached investors, the resulting losses would be partially attributable the same risk-shifting mechanisms that analysts and investors originally perceived as beneficial.

Construction Cost Caps. Some regulatory agencies approve a utility's proposed infrastructure investments only after a cap is established for the amount of investment or expense that will be allowed in rates. Assuming the regulator sticks to the deal, this action will apportion the risk between consumers and investors. We wouldn't conclude that this actually reduces risk except in the sense that working under a cap might ensure that utility management stays focused on the project, avoiding lapses into mismanagement that would raise costs and likely strain relationships with regulators and stakeholders.

Rewarding Energy Efficiency. Another relevant regulatory practice concerns the treatment of demand-side resources like energy efficiency and demand response. It is well understood that the "throughput incentive" can work to keep a utility from giving proper consideration to energy efficiency; to the extent that a utility collects more than marginal costs in its unit price for electricity, selling more electricity builds the bottom line while selling less electricity hurts profitability. There are several adjustments regulation can make, from decoupling revenues from sales, to giving utilities expedited cost recovery and incentives for energy efficiency performance. Decoupling, which guarantees that a utility will recover its authorized fixed costs regardless of its sales volumes, is generally viewed by efficiency experts and advocates as a superior approach because it neutralizes the "throughput incentive" and enables utilities to dramatically scale up energy efficiency investment without threatening profitability. Ratings agencies view decoupling mechanisms as credit positive because they provide assurance of cost recovery, and Moody's recently observed "a marked reduction in a company's gross profit volatility in the years after implementing a decoupling type mechanism."[75] Whatever the chosen approach, the takeaway here is that without regulatory intervention, energy efficiency will not likely be accorded its correct role as a low cost and low risk strategy.[76]

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4. USING FINANCIAL AND PHYSICAL HEDGES

Another method for limiting risk is the use of financial and physical hedges. These provide the utility an opportunity to lock in a price, thereby avoiding the risk of higher market prices later. Of course, this means the utility also foregoes the opportunity for a lower market price, while paying some premium to obtain this certainty.

Financial hedges are instruments such as puts, calls, and other options that a utility can purchase to limit its price exposure (e.g., for commodity fuels) to a certain profile. If the price of a commodity goes up, the call option pays off; if the price goes down, the put option pays off. Putting such a collar around risk is, of course, not free: the price of an option includes transaction costs plus a premium reflecting the instrument's value to the purchaser. Collectively these costs can be viewed as a type of insurance payment.

Another example of a financial hedge is a "temperature" hedge that can limit a utility's exposure to the natural gas price spikes that can accompany extreme weather conditions. A utility may contract with a counter-party so that, for an agreed price, the counter-party agrees to pay a utility if the number of heating-degree-days exceeds a certain level during a certain winter period. If the event never happens,

75 Moody's Investors Service, *Decoupling and 21st Century Rate Making* (New York: Moody's Investors Service, 2011), 4.

76 For a discussion of regulatory approaches to align utility incentives with energy efficiency investment, see Val Jensen, *Aligning Utility Incentives with Investment in Energy Efficiency*, ICF International (Washington, DC: National Action Plan for Energy Efficiency, 2007), http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

Long-term Contracts for Natural Gas

In recent decades, utilities have mostly used financial instruments to hedge against volatile natural gas prices, and natural gas supply used for power generation has not been sold under long-term contracts. An exception is a recent long-term contract for natural gas purchased by Xcel Energy in Colorado. The gas will be used to fuel new combined cycle units that will replace coal generating units. The contract between Xcel Energy and Anadarko contained a formula for pricing that was independent of the market price of natural gas and runs for 10 years.

The long-term natural gas contract between Xcel Energy and Anadarko was made possible by a change in Colorado's regulatory law. For years, utilities and gas suppliers had expressed concern that a long-term contract, even if approved initially as prudent, might be subject to a reopened regulatory review if the price paid for gas under the contract was, at some future date, above the prevailing market price. Colorado regulators supported legislation making it clear in law that a finding of prudence at the outset of a contract would not be subject to future review if the contract price was later "out of the money." An exception to this protection would be misrepresentation by the contracting parties.

the utility forfeits the payment made for the hedge. If the event does happen, the utility might still need to purchase natural gas at an inflated price; even so, the hedge would pay off because it has reduced the company's total outlay. Simply stated, financial hedges can be used by a utility to preserve an expected value.

An illustration of a physical hedge would be when a utility purchases natural gas at a certain price and places it into storage. The cost of that commodity is now immune to future fluctuations in the market price. Of course, there is a cost to the utility for the storage, and the utility forgoes the possible advantage of a future lower price. But in this case the payment (storage cost) is justifiable because of the protection it affords against the risk of a price increase.

Long-term contracts can also serve to reduce risk. These instruments have been used for many years to hedge against price increases or supply interruptions for coal. Similarly, long-term contracts are used by utilities to lock in prices paid to independent power producers. Many power purchase agreements (PPAs) between distribution utilities and third party generators lock in the price of capacity, possibly with a mutually-agreed price escalator. But due to possible fuel price fluctuations (especially with natural gas), the fuel-based portion of the energy charge is not fixed in these contracts. So PPAs can shield utilities from some of the risks of owning the plants, but they do not hedge the most volatile portion of natural gas generation: the cost of fuel.

Regulated utilities and their regulators must come to an understanding about whether and how utilities will utilize these options to manage risk, since using them can foreclose an opportunity to enjoy lower prices.

5. HOLDING UTILITIES ACCOUNTABLE

From the market's perspective, one of the most important characteristics of a public utilities commission is its consistency. Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators. Indeed, this quality is often viewed to be as important as the absolute level of return on equity approved by a commission.

Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators.

Effective regulation—regulation that is consistent, predictable, forward-thinking and "risk-aware"—requires that regulators hold utilities accountable for their actions. Earlier, we stressed the value of regulators being actively involved in the utility resource planning process. But this tool works well only if regulators follow through—by requiring utilities to comply with the resource plan, to amend the resource plan if circumstances change, to live within an investment cap, to adhere to a construction schedule, and so forth. If the utility doesn't satisfy performance standards, regulatory action will be necessary.

This level of activity requires a significant commitment of resources by the regulatory agency. Utility resource acquisition plans typically span ten years or more, and a regulator must establish an oversight administrative structure that spans the terms of sitting commissioners in addition to clear expectations for the regulated companies and well-defined responsibilities for the regulatory staff.

6. OPERATING IN ACTIVE, "LEGISLATIVE" MODE

As every commissioner knows, public utility regulation requires regulators to exercise a combination of judicial and legislative duties. In "judicial mode," a regulator takes in evidence in formal settings, applies rules of evidence, and decides questions like the interpretation of a contract or the level of damages in a complaint case. In contrast, a regulator operating in "legislative mode" seeks to gather all information relevant to the inquiry at hand and to find solutions to future challenges. Judicial mode looks to the past, legislative mode

to the future. In his 1990 essay, former Ohio utilities regulator Ashley Brown put it this way:

> *Gathering and processing information is vastly different in judicial and legislative models. Legislating, when properly conducted, seeks the broadest data base possible. Information and opinions are received and/or sought, heard, and carefully analyzed. The process occurs at both formal (e.g., hearings) and informal (e.g., private conversation) levels. The goal is to provide the decision maker with as much information from as many perspectives as possible so that an informed decision can be made. Outside entities can enhance, but never be in a position to limit or preclude, the flow of information. The decision maker is free to be both a passive recipient of information and an active solicitor thereof. The latter is of particular importance in light of the fact that many of the interests affected by a decision are not likely to be present in the decision making forum.*[77]

Being a risk-aware regulator requires operating in legislative mode in regulatory proceedings, and especially in policy-making proceedings such as rulemakings. But the courts have also found that ratemaking is a proper legislative function of the states.[78] And since this state legislative authority is typically delegated by legislatures to state regulators, this means that, to some extent, regulators may exercise "legislative" initiative even in rate-setting cases.

In a recent set of essays, Scott Hempling, the former executive director of the National Regulatory Research Institute, contrasts regulatory and judicial functions and calls for active regulation to serve the public interest:

> *Courts and commissions do have commonalities. Both make decisions that bind parties. Both base decisions on evidentiary records created through adversarial truth-testing. Both exercise powers bounded by legislative line-drawing. But courts do not seek problems to solve; they wait for parties' complaints. In contrast, a commission's public interest mandate means it literally looks for trouble. Courts are confined to violations of law, but commissions are compelled to advance the public welfare.*[79]

Utility resource planning is one of the best examples of the need for a regulator to operate in legislative mode. When examining utilities' plans for acquiring new resources, regulators must seek to become as educated as possible. Up to a point, the more choices the better. The regulator should insist that the utility present and analyze multiple alternatives. These alternatives should be characterized fully, fairly, and without bias. The planning process should seek to discover as much as possible about future conditions, and the door should be opened to interveners of all stripes. Knowing all of the options—not simply the ones that the utility brings forward—is essential to making informed, risk-aware regulatory decisions.

The planning process should seek to discover as much as possible about future conditions, and the door should be opened to interveners of all stripes. Knowing all of the options—not simply the ones that the utility brings forward—is essential to making informed, risk-aware regulatory decisions.

7. REFORM AND RE-INVENT RATEMAKING PRACTICES

It is increasingly clear that a set of forces is reshaping the electric utility business model. In addition to the substantial investment challenge discussed in this report, utilities are facing challenges from stricter environmental standards, growth in distributed generation, opportunities and challenges with the creation of a smarter grid, new load from electric vehicles, pressure to ramp up energy efficiency efforts—just to mention a few. As electric utilities change, regulators must be open to new ways of doing things, too.

77 Ashley Brown, "The Over-judicialization of Regulatory Decision Making," *Natural Resources and Environment* Vol. 5, No. 2 (Fall 1990), 15-16.

78 See, e.g., U.S. Supreme Court, *Munn vs. Illinois*, 94 U.S. 113 (1876), http://supreme.justia.com/cases/federal/us/94/113/case.html.

79 Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators* (Silver Spring, MD: National Regulatory Research Institute, 2011), 22.

Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades. To deal with the digital revolution in telecommunications and the liberalization of those markets, regulators modernized their tools to include various types of incentive regulation, pricing flexibility, lessened regulation in some markets and a renewed emphasis on quality of service and customer education.

One area where electric utility regulators might profitably question existing practices is rate design. Costing and pricing decisions, especially for residential and small business customers, have remained virtually unchanged for decades. The experience in other industries (e.g., telecommunications, entertainment, music) shows that innovations in pricing are possible and acceptable to consumers. Existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

The risk-aware regulator must be willing to think "way outside the box" when it comes to the techniques and strategies of effective regulation. Earlier we observed that effective regulators must be informed, active, consistent, curious and often courageous. These qualities will be essential for a regulator to constructively question status quo regulatory practice in the 21st century.

THE BENEFITS OF "RISK-AWARE REGULATION"

We have stressed throughout this report that effective utility regulators must undertake a lot of hard work and evolve beyond traditional practice to succeed in a world of changing energy services, evolving utility companies and consumer and environmental needs. What can regulators and utilities reasonably expect from all this effort? What's the payback if regulators actively practice "risk-aware regulation"?

- **FIRST**, there will be benefits to consumers. A risk-aware regulator is much less likely to enter major regulatory decisions that turn out wrong and hurt consumers. The most costly regulatory lapses over the decades have been approval of large investments that cost too much, failed to operate properly, or weren't needed once they were built. It's too late for any regulator to fix the problem once the resulting cost jolts consumers.
- **SECOND**, there will be benefits to regulated utilities. Risk aware regulation will create a more stable, predictable business environment for utilities and eliminate most regulatory surprises. It will be easier for these companies to plan for the longer-term. If regulators use a well-designed planning process, examining all options and assessing risks, utilities and their stakeholders will have greater reliance on the long-term effect of a decision.
- **THIRD**, investors will gain as well. Steering utilities away from costly mistakes, holding the companies responsible for their commitments and, most importantly, maintaining a consistent approach across the decades will be "credit-positive," reducing threats to cost-recovery. Ratings agencies will take notice, lowering the cost of debt, benefitting all stakeholders.
- **FOURTH**, governmental regulation itself will benefit. Active, risk-aware regulators will involve a wide range of stakeholders in the regulatory process, building support for the regulators' decision. Consistent, transparent, active regulation will help other state officials—governors and legislators—develop a clearer vision of the options for the state's energy economy.
- **FINALLY**, our entire society will benefit as utilities and their regulators develop a cleaner, smarter, more resilient electricity system. Regulation that faithfully considers all risks, including the future environmental risks of various utility investments, will help society spend its limited resources most productively. In other words, risk-aware regulation can improve the economic outcome of these large investments.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

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APPENDIX 1:

UNDERSTANDING UTILITY FINANCE

MOST INVESTOR-OWNED UTILITIES (IOUS) IN THE UNITED STATES ARE IN A CONSTRUCTION CYCLE OWING TO THE NEED TO COMPLY WITH MORE STRINGENT AND EVOLVING ENVIRONMENTAL POLICIES AND TO IMPROVE AGING INFRASTRUCTURE. NEW INFRASTRUCTURE PROJECTS INCLUDE SMART GRID, NEW GENERATION AND TRANSMISSION. THE IOUS, THEREFORE, WILL BE LOOKING TO THE CAPITAL MARKETS TO HELP FINANCE THEIR RATHER LARGE CAPITAL EXPENDITURE PROGRAMS.

DEBT FINANCING

While the IOUs will be issuing some additional equity, a higher percentage of the new investment will be financed with debt. In general, utilities tend to be more leveraged than comparably-rated companies in other sectors (see the Rating Agencies section below). The electric utility sector's debt is primarily publicly issued bonds, including both first mortgage bonds (FMB) and senior unsecured bonds. While the utilities also issue preferred stock and hybrid debt securities, these instruments tend to represent a small portion of a company's capital structure. Non-recourse project finance is rare for utilities, but it is commonly used by unregulated affiliates.

Most regulated IOUs in the U.S. are owned by holding companies whose assets are primarily their equity interests in their respective subsidiaries. These operating company subsidiaries are typically wholly owned by the parent, so that all publicly-held stock is issued by the parent. Because most of these holding companies are quite large, the market for a holding company's stock is usually highly liquid.

In contrast to equity, bonds are issued by both the utility holding company and individual operating subsidiaries. Typically, holding and operating company bonds are non-recourse to affiliates. This means that each bond issuer within the corporate family will have its own credit profile that affects the price of the respective bonds. To illustrate this point, compare two American Electric Power subsidiaries, Ohio Power and Indiana Michigan. The companies have different regulators, generation mix, customer bases and, consequently, different senior unsecured Moody's bond ratings of Baa1 and Baa2, respectively. For this reason, each bond issuance of the corporate family trades somewhat independently.

Utility bonds trade in secondary markets and are traded over-the-counter rather than in exchanges like equities. For bond issuance of less than $300 million, the secondary market is illiquid and not very robust. Smaller utilities are frequently forced into the private placement market with their small issuances and accordingly pay higher interest rates compared to similarly-rated larger companies. Even if these smaller issues are placed in the public market, there is a premium for the expected lack of liquidity.

Secured debt in the form of FMBs is common in the electric utility sector. Such bonds are usually secured by an undivided lien on almost all of the assets of an operating utility. Bond documentation (called an "indenture") prohibits the issuance of such bonds in an amount that exceeds a specified percentage (usually in the range of 60 percent) of the asset value of the collateral. The maturities of these bonds are frequently as long as 30 years, and in rare occasions longer). While the lien on assets may limit a company's financing flexibility, the interest rate paid to investors is lower than for unsecured debt. The proceeds from FMBs are usually used to finance or refinance long-lived assets.

Senior unsecured bonds can be issued at any maturity, but terms of five and ten years are most common. These instruments are "junior" to FMBs, so that, in an event of default, these debt holders would be repaid only after the secured debt. But these bonds are "senior" to hybrids and preferred stock. In a bankruptcy, senior unsecured bonds are usually deemed equal in standing with trade obligations, such as unpaid fuel and material bills.

Utilities typically have "negative trade cycles," meaning that cash receipts tend to lag outlays. IOUs' short-term payables such as fuel purchases, salaries and employee benefits are due in a matter of days after the obligation is incurred. In contrast, the utility's largest short-term assets are usually customer receivables which are not due for 45—60 days after the gas or electricity is delivered. Therefore, utilities have short term cash needs referred to as "working capital" needs. To finance these short term needs utilities have bank credit lines and sometimes trade receivable facilities.

For larger utility corporate families, these bank lines can amount to billions of dollars. For example, American Electric Power has two large bank lines of $1.5 and $1.7 billion that mature in 2015 and 2016, respectively. AEP's lines and most of those of other utilities are revolving in nature. While termination dates typically range from one to five years for these lines, the utility usually pays down borrowings in a few months and accesses the line again when needed.

Interest on bank lines of credit is paid only when the lines are used, with a much lower fee paid on the unused portion of the lines. For financially weak utility companies, banks often require security for bank lines . But because utility operating companies are rarely rated below BBB-/Baa3, bank lines are, for the most part, unsecured.

Some larger utilities have receivable facilities in addition to revolving bank lines. The lender in a receivables facility usually purchases the customer receivables. There is an assumed interest expense in these transactions which is usually lower than the rate charged by banks for unsecured revolving lines.

Although preferred stock is a form of equity, it is usually purchased by a bond investor who is comfortable with the credit quality of the issuer and willing to take a junior position in order to get a higher return on its investment. There are also hybrid securities. Although they are technically debt instruments, they are so deeply subordinate and with such long repayment periods that investors and the rating agencies view these instruments much like equities. Frequently, hybrids allow the issuer to defer interest payments for a number of years. Some hybrids can be converted to equity at either the issuer's or investor's option.

S&P is the most rigorous of the rating agencies in treating the fixed component of power purchase agreements (PPA) as debt-like in nature. Also, some Wall Street analysts look at PPAs as liabilities with debt-like attributes. That being said, those analysts who do not consider PPAs as debt-like still incorporate in their analysis the credit implications of these frequently large obligations.

EQUITY FINANCING

In order to maintain debt ratings and the goodwill of fixed income investors, utility managers must finance some portion of their projects with equity. Managements are usually reluctant to go to market with large new stock issuances. Equity investors often see new stock as being dilutive to their interests, resulting in a decrease in the market price of the stock. But if a utility has a large capital expenditure program it may have no choice but to issue equity in order maintain its credit profile.

For more modest capital expenditure programs, a company may be able to rely on incremental increases to equity to maintain a desired debt to equity ratio. While the dividend payout ratios are high in this sector, they are rarely 100 percent, so that for most companies, equity increases, at least modestly, through retained earnings. Many companies issue equity in small incremental amounts every year to fulfill commitments to employee pension or rewards programs. Also, many utility holding companies offer their existing equity holders the opportunity to reinvest dividends in stock. For larger companies these programs can add $300 - $500 million annually in additional equity. Since these programs are incremental, stock prices are usually unaffected.

OTHER FINANCING

Project finance (PF) can also be used to fund capital expenditures. These instruments are usually asset-specific and non-recourse to the utility, so that the pricing is higher than traditional investment-grade utility debt. Project finance is usually used by financially weaker non-regulated power developers.

Some companies are looking to PF as a means of financing large projects so that risk to the utility is reduced. However, the potential of cost overruns, the long construction/development periods and use of new technology will make it hard to find PF financing for projects like new nuclear plants. This also applies to carbon capture/sequestration projects, as the technology is not seasoned enough for most PF investors. This means that, utilities may need to finance new nuclear and carbon capture/ sequestration projects using their existing balance sheets.

In order to reduce risk, a utility can pursue projects in partnership with other companies. Currently proposed large gas transport and electric transmission projects are being pursued by utility consortiums. Individual participants in gas transport projects in particular have used Master Limited Partnerships (MLPs) as a way to finance their interests. MLPs are owned by general and limited partners. Usually the general partner is the pipeline utility or a utility holding company. Limited partner units are sold to passive investors and are frequently traded on the same stock exchanges that list the parent company's common stock. One big difference between the MLP and an operating company is that earnings are not subject to corporate income tax. The unit holders pay personal income tax on the profits.

Companies have used both capital and operating lease structures to finance discrete projects, including power plants. The primary difference between an operating and capital lease is that the capital lease is reflected on the company's balance sheet. The commitment of the utility to the holder of the operating lease is deemed weaker. Most fixed income analysts, as well as the rating agencies, do not view these instruments as being materially different and treat operating leases for power plants as debt.

TYPICAL UTILITY INVESTORS

The largest buyers of utility equities and fixed income securities are large institutional investors such as insurance companies, mutual funds and pension plans. As of September 2011, 65 percent of utility equities were owned by institutions. While insurance companies and pension plans own utility equities, both trail mutual funds in the level of utility stock holdings. For example, the five largest holders of Exelon stock are mutual fund complexes.

Most retail investors own utility stock and bonds indirectly through mutual funds and 401k plans. But many individual investors also own utility equities directly, including utility employees. Small investors tend not to buy utility bonds because the secondary market in these instruments is rather illiquid, especially if the transaction size is small.

Common stock mutual funds with more conservative investment criteria are most interested in utility equities. While the market price of these stocks can vary, there is a very low probability of a catastrophic loss. Also, utility stocks usually have high levels of current income through dividend distributions. Another attractive attribute of these equities is that they are highly liquid. Essentially all utilities in the U.S. are owned by utility holding companies that issue common stock. Due to extensive consolidation in the sector over the past 20 years, these holding companies are large and have significant market capitalization. For these reasons, utility stocks are highly liquid and can be traded with limited transaction costs.

Utility fixed-income investments are far less liquid than equities. Thus, the typical bond investor holds onto the instruments much longer than the typical equity investor. Bonds are issued both by the utility holding company and individual operating subsidiaries. Because bonds are less liquid in the secondary market, investors in these instruments, such as pension plans and insurance companies, tend to have longer time horizons. Four of the top five investors in Exelon Corp bonds due 2035 are pension plans and insurance companies. Mutual bond funds tend to buy shorter-dated bonds.

The buyers of first mortgage bonds (FMBs) are frequently buy-and-hold investors. As FMBs are over-collateralized, bondholders are comfortable that they will be less affected by unforeseen negative credit events. It is not unusual for a large insurance company to buy a large piece of an FMB deal at issuance and hold it to maturity. Retail investors in utility bonds also tend to be buy-and-hold investors, as it is hard for them to divest their positions which are typically small compared to the large institutions. The relative illiquidity of utility bonds means that transaction costs can be high and greatly reduce the net proceeds from a sale.

Utility employees frequently own the stock of the companies for which they work. Employees with defined benefit pensions, however, are not large holders of utility stocks because pension plans hold little if any of an employer's stock owing to ERISA rules and prudent asset management practices. Mid-level non-unionized employees frequently have 401ks that are typically invested in mutual funds or similar instruments. However, it is not unusual for company matching of the employees' 401k contributions to be in company stock. Finally, senior management's incentive compensation is frequently paid in the company's common equity, in part to ensure that management's interests are aligned with those of the shareholders.

RATING AGENCIES

Most utilities have ratings from three rating agencies: Moody's Investors Services, Standard & Poor's Ratings Services, and Fitch Ratings. Having three ratings is unlike other sectors, which frequently use two ratings—Moody's or Standard & Poor's. Most utility bonds are held by large institutional investors who demand that issuers have at least Moody's and Standard & Poor's ratings.

Failing to have two ratings would cause investors to demand a very high premium on their investments, far more than the cost to utilities of paying the agencies to rate them. Having a third rating from Fitch usually slightly lowers the interest rate further. While investors have become less comfortable with the rating agencies' evaluations of structured finance transactions, this dissatisfaction has not carried over greatly into the corporate bond market, and especially not the utility bond market.

The agencies usually assign a rating for each company referred to as an *issuer rating*. They also rate specific debt issues, which may be higher or lower than the issuer rating. Typically a secured bond will have a higher rating than its issuer; preferred stock is assigned a lower rating than the issuer. Ratings range from AAA to D.[80] The "AAA" rating is reserved for entities that have virtually no probability of default. A "D" rating indicates that the company is in default.

The three agencies each take into account both the probability of default, as well as the prospects of recovery for the bond investor if there is a default. Utilities traditionally are considered to have high recovery prospects because they are asset-heavy companies. In other words, if liquidation were necessary, bond holders would be protected because their loans are backed by hard assets that could be sold to cover the debt. Further, the probability of default is low because utility rates are regulated, and regulators have frequently increased rates when utilities have encountered financial

80 Standard & Poor's and Fitch use the same ratings nomenclature. It was designed by Fitch and sold to S&P. For entities rated between AA and CCC the agencies break down each rating category further with a plus sign or a minus sign. For example, bonds in the BBB category can be rated BBB+, BBB and BBB-. Moody's ratings nomenclature is slightly different. The corresponding ratings in BBB category for Moody's are Baa1, Baa2 and Baa3. The agencies will also provide each rating with an outlook that is stable, positive or negative.

problems owing to events outside of companies' control. However, there are a few notable instances where commissions could not or would not raise rates to avoid defaults including the bankruptcies of Public Service of New Hampshire and Pacific Gas and Electric.

It is unusual for a utility operating company to have a non-investment grade rating (Non-IG, also referred to as high yield, speculative grade, or junk). Typically Non-IG ratings are the result of companies incurring sizable expenses for which regulators are not willing or able to give timely or adequate rate relief. Dropping below IG can be problematic for utilities because interest rates increase markedly. Large institutional investors have limited ability to purchase such bonds under the investment criteria set by their boards. Another problem with having an Non-IG rating is that the cost of hedging rises owing to increased collateral requirements as counterparties demand greater security from the weakened credit.

In developing their ratings, the agencies consider both quantitative and more subjective factors. The quantitative analysis tends to look at cash flow "coverage" of total debt and of annual fixed income payment obligations, as well as overall debt levels. In contrast, the typical equity analyst focuses on earnings. The rating agencies are less interested in the allowed returns granted by regulators than they are in the size of any rate decrease or increase and its effect on cash flow.

That said, the rating agency may look at allowed returns to evaluate the "quality" of regulation in a given state. All things being equal, they may give a higher rating to a company in a state with "constructive" regulation than to a company in a state with a less favorable regulatory climate. Constructive regulation to most rating agencies is where regulatory process is transparent and consistent across issuers in the state. Also, the agencies favor regulatory constructs that use forward-looking test years and timely recovery of prudently-incurred expenses. The agencies consider tracking mechanisms for fuel and purchased power costs as credit supportive because they help smooth out cash fluctuations. The agencies believe that while trackers result in periodic changes in rates for the customer, these mechanisms are preferable for consumers than the dramatic change in rates caused by fuel factors being lumped in with other expenses in a rate case.

Analysts also will look to see how utility managers interact with regulators. The agencies deem it a credit positive if management endeavors to develop construct relationships with regulators. The agencies may become concerned about the credit quality of a company if the state regulatory process becomes overly politicized. This may occur if a commission renders decisions with more of an eye toward making good press than applying appropriate utility regulatory standards. Politicized regulatory environments can also occur when a commission is professional and fair, but outside political forces, such as governors, attorneys general or legislators challenge a prudently decided case.

The rating agencies themselves can at times act as *de facto* regulators. Because utilities are more highly levered than most any other sector, interest expenses can be a significant part of a company's cost structure. Ratings affect interest rates. The agencies will look negatively at anything that increases event risk. The larger an undertaking, the greater the fallout if an unforeseen event undermines the project. A utility embarking on the development of a large facility like a large generation or transmission project, especially if is not preapproved by the regulators, might result in a heightened focus on the company by the agencies. The rating action could merely be change in outlook from stable to negative, which could in turn have a negative impact on the market price of outstanding bonds, interest rates on new issuances and even on equity prices. Many utility stock investors are conservative and pay more attention to rating agency comments and actions than investors with holdings in more speculative industries.

APPENDIX 2:

TOOLS IN THE IRP PROCESS

REGULATORS HAVE SEVERAL TOOLS AT THEIR DISPOSAL IN THE IRP PROCESS. ONE OF THE MOST IMPORTANT IS THE UTILITY REDISPATCH MODEL. THIS IS A COMPLEX COMPUTER PROGRAM THAT SIMULATES THE OPERATION OF A UTILITY'S SYSTEM UNDER INPUT ASSUMPTIONS PROVIDED BY THE USER. THE TERM "REDISPATCH" REFERS TO THE FACT THAT THE SOFTWARE MIMICS THE OPERATION OF AN ACTUAL UTILITY SYSTEM, "DISPATCHING" THE HYPOTHETICAL GENERATION RESOURCES AGAINST A MODEL LOAD SHAPE, OFTEN HOUR-BY-HOUR FOR MOST COMMONLY USED MODELS.

Three examples of these models are Prosym, licensed by Henwood Energy Services; Strategist, licensed by Ventyx; and GE MAPS, licensed by General Electric.

A model typically creates a 20- or 40-year future utility scenario, based on load projections provided by the user. The utility's energy and peak demand is projected for each hour of the time period, using known relationships about loads during different hours, days of the week and seasons of the year. The model then "dispatches" the most economic combination of existing or hypothetical new resources to meet the load in every hour of that time period.

The operating characteristics of each generating resource is specified as to its availability, fuel efficiency, fuel cost, maintenance schedule, and, in some models, its emissions profile. The resources available to the model will be a mixture of existing plants, taking note of their future retirement dates, plus any hypothetical new resources required by load growth. The model incorporates estimates of regional power purchases and their price, transmission paths and their constraints, fuel contracts, the retirement of existing facilities, etc.

In this way, the user of the model can test various combinations (scenarios) of proposed new generating plants, including base load plants, intermediate and peaking plants, intermittent renewable resources, etc. The model will calculate the utility's revenue requirement, fuel costs, and purchased power expenses in each scenario. The model might be used to estimate the cost of operating the system with a specific hypothetical portfolio, predict the level of emissions for a portfolio, measure the value of energy efficiency programs, test the relative value of different resources, measure the reliability of the system, etc.

The reader might analogize this modeling to "fantasy" baseball, where hypothetical teams play hypothetical games, yielding win-loss records, batting averages and pennant races.

As powerful as these modeling tools are, they are *production* models, first and foremost. As such, they are not particularly good at dealing with assumptions about energy efficiency and demand response. In using such models, the regulator must insist that the utility gives appropriate treatment to demand-side resources. It may be possible to re-work models to do this, or it may be necessary to conduct extra sensitivity analyses at varying levels of energy efficiency and demand response.

IRP SENSITIVITY ANALYSES

A redispatch modeling tool allows a utility and the regulator to test the resilience of portfolios against different possible futures. For example, a regulator might want to know how five different generation portfolios behave under situations of high natural gas prices, or tougher environmental regulations. By varying the input assumptions while monitoring the relevant output (e.g., net present value of future revenue requirements) the regulator can assess the risk that contending portfolios pose to future rates if, for example, fuel prices vary from their predicted levels.

To illustrate this idea, consider the following material from a case in Colorado. **Figure Appendix - 1** is a page excerpted from Xcel Energy's 2009 analysis in support of a resource plan filed before the Colorado Public Utilities Commission. The page shows the results of sensitivity analyses for the price of natural gas (high and low) and the cost of carbon emissions (high and low) for twelve different portfolios being considered by the Colorado PUC.

In all, the Colorado PUC studied 48 different generation portfolios in this IRP case. The portfolios differed based on how much natural gas generation was added, how much wind and solar generation was added, the schedule for closing some existing coal-fired power plants, the level of energy efficiency assumed, etc. (The actual generation units in each portfolio are not identified in this public document.

Figure Appendix - 1

EXAMPLE OF IRP SENSITIVITY ANALYSES

Base Scenario Assumption: High Efficiency, Medium Solar

Representative of Preferred Plan

Primary Scenario
High DSM (130% Goal)
Medium Section 123 (200 MW)
Base Load

Portfolios 1-12

Key Portfolio Characteristic		1	2	3	4	5	6	7	8	9	10	11	12
		Portfolio Number											
		1	2	3	4	5	6	7	8	9	10	11	12
		Portfolio Rank within Scenario (PVRR)											
		1	2	3	4	5	6	7	8	9	10	11	12
Wind (MW)													
Solar (MW)													
Intermittent (MW)													
Solar Storage (MW)													
Gas (MW)													
Other (MW)	1												
Total (MW)		1,872	1,902	1,907	1,932	1,977	1,966	1,911	1,860	1,936	2,039	1,982	2,078
Owned %													
Owned MW													
Total 123 (MW)													
CO2 (M ton)	2	26.8	26.7	26.8	26.7	26.6	26.8	26.8	26.8	26.9	26.6	26.5	26.6
% New Build	3												
Externalities	4	2	2	2	2	2	1	2	2	1	2	3	2
PVRR & Rank													
PVRR rank		1	2	3	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	49,344	49,361	49,365	49,387	49,402	49,478	49,490	49,526	49,645	49,675	49,675	49,822
PVRR Delta ($M)	6	-	17	21	43	58	134	146	182	301	331	331	478
PV Rate ($/MWh)	7	71.87	71.90	71.90	71.94	71.96	72.07	72.09	72.14	72.31	72.36	72.36	72.57
CO2 Delta (M ton)	8	-	(0.30)	(0.02)	(0.50)	(0.68)	1.79	(0.09)	(0.04)	0.80	(0.57)	(0.81)	(0.65)
$10/ton CO2 Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	43,695	43,722	43,716	43,758	43,786	43,805	43,845	43,877	43,981	44,054	44,080	44,203
Change ($M)	10	(5,649)	(5,638)	(5,649)	(5,628)	(5,616)	(5,673)	(5,645)	(5,649)	(5,664)	(5,622)	(5,596)	(5,619)
PVRR Delta ($M)	11	-	27	21	63	91	110	150	182	286	358	384	508
$40/ton CO2 Sensitivity (PVRR & Rank)													
PVRR rank	9	3	2	5	4	1	7	6	8	11	10	9	12
PVRR ($M)	5	60,066	60,061	60,087	60,067	60,056	60,247	60,204	60,250	60,392	60,311	60,285	60,451
Change ($M)	10	10,723	10,701	10,723	10,680	10,654	10,769	10,714	10,724	10,747	10,636	10,610	10,629
PVRR Delta ($M)	11	10	5	31	11	-	191	148	194	336	255	229	395
Low Gas Price Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	10	9	11	12
PVRR ($M)	5	47,935	47,959	47,956	47,992	48,016	48,055	48,075	48,118	48,234	48,230	48,318	48,371
Change ($M)	10	(1,409)	(1,402)	(1,409)	(1,395)	(1,386)	(1,423)	(1,415)	(1,407)	(1,411)	(1,445)	(1,357)	(1,451)
PVRR Delta ($M)	11	-	24	22	57	81	121	140	184	299	295	383	436
High Gas Price Sensitivity													
PVRR rank	9	5	4	6	3	1	7	8	10	9	11	2	12
PVRR ($M)	5	57,122	57,091	57,144	57,070	57,025	57,295	57,326	58,234	57,421	58,268	57,059	58,464
Change ($M)	10	7,778	7,730	7,780	7,684	7,623	7,817	7,836	8,708	7,776	8,593	7,384	8,642
PVRR Delta ($M)	11	97	66	120	46	-	270	302	1,209	396	1,244	34	1,439

Otherwise, it would have created problems for the competitive bidding process used to award contracts to supply the power to the utility.)

Each column in the table represents a different portfolio, numbered 1 to 12. Portfolio 2 is the Xcel's preferred plan. The rows show the modeling results for each portfolio. For example, the Present Value of Revenue Requirements (PVRR) is calculated for each portfolio and is shown the line indicated by the first PVRR arrow, along with the ranking of that portfolio. The lower half of the chart shows the cost of each portfolio under different assumptions about the cost of carbon emissions (higher or lower than base case predictions) and for natural gas prices (higher or lower than base case predictions).

CAVEATS

Models are a terrific way to keep track of all the moving parts in the operation of a utility portfolio. But it is one thing to know that each resource has certain operating characteristics; it is quite another to see these qualities interact with each other in dynamic fashion. And while utility modeling tools, such as production cost models can be helpful, care must be taken with their use.

Obviously the models are helpful only to the extent that the inputs are reasonable and cover the range of possibilities the regulator wishes to examine. Load forecast must be developed with care; assumptions about future fuel costs are really educated guesses, and should be bracketed with ranges of sensitivity.

Because there are so many possible combinations, variations and sensitivities, the regulator in an IRP case must make a decision early in the process about the scope of the portfolios to be examined. The utility should be directed to analyze and present all scenarios requested by the regulator, together with any portfolios preferred by the utility.

Finally, the model's best use is to inform judgment, not substitute for it. The amount of data produced by models can be overwhelming and may give a false sense of accuracy. The risk-aware regulator will always understand the fundamental uncertainties that accompany projections of customer demand, future fuel costs and future environmental requirements.

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FPO Union Label

Consumers Energy Evaluation of Economics of Big 5 Coal Plant Operation Beyond 2015

			Purchase Capacity Needs All Years				~1,000 MW Max Purchases, Optimized with New Gas			
Line	Description	Units	NPV of Net System Revenue Requirements for Early Retirements Scenario	NPV of Net System Revenue Requirements for Continued Operation Scenario	NPV of Net System Cost / (Savings) of Early Retirements	Cost / (Savings) as % of Continued Operation Scenario	NPV of Net System Revenue Requirements for Early Retirements Scenario	NPV of Net System Revenue Requirements for Continued Operation Scenario	NPV of Net System Cost / (Savings) of Early Retirements	Cost / (Savings) as % of Continued Operation Scenario
			(f)	(g)	(h)		(i)	(j)	(k) 1	(k) 2
1	Base scenario	($M)	40,611	38,543	2,068	5.37%	38,532	37,661	870	2.31%
2	Capacity price sensitivity - - 75% New CT	($M)	39,189	37,658	1,531	4.07%	38,283	37,425	858	2.29%
3	Capacity price sensitivity - - 50% New CT	($M)	37,768	36,773	994	2.70%	38,035	37,189	846	2.27%
4	Capacity price sensitivity - - High Volatility, Short Cycle	($M)	39,298	37,681	1,617	4.29%	38,324	37,466	857	2.29%
5	Capacity price sensitivity - - High Volatility, Long Cycle	($M)	38,696	37,333	1,363	3.65%	38,217	37,381	835	2.23%
6	Capacity price sensitivity - - Low Volatility, Short Cycle	($M)	39,739	37,979	1,761	4.64%	38,390	37,528	862	2.30%
7	Capacity price sensitivity - - Low Volatility, Long Cycle	($M)	39,545	37,911	1,634	4.31%	38,348	37,490	859	2.29%

Source David F. Ronk's Exhibit A-50 (DFR-5)

Synapse Evaluation of Economics of Big 5 Coal Plant Operation Beyond 2015

Company Base Case assumptions			NPV of Net System Revenue Requirements	NPV of Net System Revenue Requirements for 1x1 Strategies	NPV of Net System Cost / (Savings) vs Continued Operation Strategy	Cost / (Savings) as % of Continued Operation Scenario
(a)	(b)	(c)	(d)	(e)	(f) = (e) - (d)	(g) = (f) / (d)
	Resource Strategies					
1	Continued Operation Strategy	($M)	32,174,120	N/A	N/A	N/A
2	Retire Karn 1	($M)	32,174,120	32,487,688	313,568	1.0%
3	Retire Karn 2	($M)	32,174,120	32,516,768	342,648	1.1%
4	Retire Campbell 1	($M)	32,174,120	32,445,358	271,238	0.8%
5	Retire Campbell 2	($M)	32,174,120	32,263,420	89,300	0.3%
6	Retire Campbell 3	($M)	32,174,120	33,036,016	861,896	2.7%
7	Retire Karn 1&2	($M)	32,174,120	32,508,572	334,452	1.0%
8	**Retire Campbell 1&2**	($M)	32,174,120	32,220,230	**46,110**	**0.1%**

EIA AEO 2012 Reference Case Henry Hub Gas price projection			NPV of Net System Revenue Requirements	NPV of Net System Revenue Requirements for 1x1 Strategies	NPV of Net System Cost / (Savings) vs Continued Operation Strategy	Cost / (Savings) as % of Continued Operation Scenario
(a)	(b)	(c)	(d)	(e)	(f) = (e) - (d)	(g) = (f) / (d)
1	Continued Operation Strategy	($M)	31,291,084	N/A	N/A	N/A
2	Retire Karn 1	($M)	31,291,084	31,007,724	(283,360)	-0.9%
3	Retire Karn 2	($M)	31,291,084	31,031,524	(259,560)	-0.8%
4	Retire Campbell 1	($M)	31,291,084	30,921,990	(369,094)	-1.2%
5	Retire Campbell 2	($M)	31,291,084	30,870,396	(420,688)	-1.3%
6	Retire Campbell 3	($M)	31,291,084	31,279,034	(12,050)	0.0%
7	Retire Karn 1&2	($M)	31,291,084	30,721,454	(569,630)	-1.8%
8	**Retire Campbell 1&2**	($M)	31,291,084	30,460,584	**(830,500)**	**-2.7%**

Synapse 2012 Low Case Carbon Cost Forecast + EIA AEO 2012 Reference Case Henry Hub Gas price projection			NPV of Net System Revenue Requirements	NPV of Net System Revenue Requirements for 1x1 Strategies	NPV of Net System Cost / (Savings) vs Continued Operation Strategy	Cost / (Savings) as % of Continued Operation Scenario
(a)	(b)	(c)	(d)	(e)	(f) = (e) - (d)	(g) = (f) / (d)
1	Continued Operation Strategy	($M)	31,966,478	N/A	N/A	N/A
2	Retire Karn 1	($M)	31,966,478	31,624,678	(341,800)	-1.1%
3	Retire Karn 2	($M)	31,966,478	31,653,580	(312,898)	-1.0%
4	Retire Campbell 1	($M)	31,966,478	31,651,960	(314,518)	-1.0%
5	Retire Campbell 2	($M)	31,966,478	31,472,020	(494,458)	-1.5%
6	Retire Campbell 3	($M)	31,966,478	31,645,770	(320,708)	-1.0%
7	Retire Karn 1&2	($M)	31,966,478	31,278,496	(687,982)	-2.2%
8	**Retire Campbell 1&2**	($M)	31,966,478	31,001,018	**(965,460)**	**-3.0%**

Evaluation of Economics of Big 5 Coal Plant Operation Beyond 2015 (Nom$, million)

Resource Strategies		Cost / (Savings) as % of Continued Operation Scenario			
		Consumers Energy Evaluations	Synapse Evaluations		
		Company Base Case	Company Base Case	EIA AEO 2012 Reference Case Henry Hub Gas price projection	Synapse 2012 Low Case Carbon Cost Forecast + EIA AEO 2012 Reference Case Gas price
1	**Continued Operation Strategy**				
2	Early Retirements + Purchase Capacity Needs All Years	5.37%	N/a	N/a	N/a
3	Early Retirements + 1,000 MW Max Purchases, Optimized with New Gas	2.31%	N/a	N/a	N/a
4	**Retire Karn 1**; Retrofit Karn 2 and Campbell 1 to 3; 1,000 MW Max Purchases, Optimized with New Gas	N/a	1.0%	-0.9%	-1.1%
5	**Retire Karn 2**; Retrofit Karn 1 and Campbell 1 to 3; 1,000 MW Max Purchases, Optimized with New Gas	N/a	1.1%	-0.8%	-1.0%
6	**Retire Campbell 1**, Retrofit Karn 1 & Karn 2 and Campbell 2 & 3; 1,000 MW Max Purchases, Optimized with New Gas	N/a	0.8%	-1.2%	-1.0%
7	**Retire Campbell 2;** Retrofit Karn 1 & Karn 2 and Campbell 1 & 3; 1,000 MW Max Purchases, Optimized with New Gas	N/a	0.3%	-1.3%	-1.5%
8	**Retire Campbell 3**, Retrofit Karn 1 & Karn 2 and Campbell 1 &2; 1,000 MW Max Purchases, Optimized with New Gas	N/a	2.7%	0.0%	-1.0%
9	**Retire Karn 1 & 2**; Retrofit Campbell 1 to 3; 1,000 MW Max Purchases, Optimized with New Gas	N/a	1.0%	-1.8%	-2.2%
10	**Retire Campbell 1 & 2**; Retrofit Karn 1 & 2 and Campbell 3; 1,000 MW Max Purchases, Optimized with New Gas	N/a	**0.1%**	**-2.7%**	**-3.0%**

17087-MEC-CE-78 (redacted)

<u>Question:</u>

29. Refer to the direct testimony of David Ronk; refer to Exhibits A-48, A-49, A-50 and A-51.

a) List the input data and input assumptions for each of the four exhibits.

b) Identify the source of each input or assumption, and produce the source if available.

c) Produce the models underlying the four exhibits, in electronic, machine readable format with inputs, outputs, and formulas intact.

d) If not contained in the inputs, identify the year through which the analysis in each exhibit was run.

e) Identify the dates when the analyses underlying each of these four exhibits were conducted. (This question seeks the dates of the analyses included into the exhibits, not the dates the exhibit themselves were finalized.)

f) State whether any of the analyses in Exhibit A-48 were run for any of the 7 Classic units individually. If not, explain why not.

g) State whether any of the analyses in Exhibit-48 were run for some combination of the 7 Classic units other than all or none. If not, explain why not.

h) If the answer to either or both of the previous two sub-parts is yes, provide those analyses in electronic form, as well as the electronic input assumptions and sources if different from the input assumptions and sources provided in sub-part (a).

i) State whether any of the analyses in Exhibit A-49 were run for any of the 7 Classic units individually. If not, explain why not.

j) State whether any of the analyses in Exhibit A-49 were run for some combination of the 7 Classic units other than all or none? If not, explain why not.

k) If the answer to either or both of the previous two sub-parts is yes, provide those analyses in electronic form, as well as the electronic input assumptions and sources if different from the input assumptions and sources provided in sub-part (a).

l) State whether any of the analyses in Exhibit A-50 were run for any of the Big 5 units individually. If not, explain why not.

m) State whether any of the analyses in Exhibit A-50 were run for some combination of the Big 5 units other than all or none? If not, explain why not.

n) If the answer to either or both of the previous two sub-parts is yes, provide those analyses in electronic form, as well as the electronic input assumptions and sources if different from the input assumptions and sources provided in sub-part (a).

o) State whether the company ran any other scenarios regarding operation of the big five coal plants beyond 2015. If so, produce such analysis and results, including all inputs and outputs in electronic machine readable format with formulas intact.

p) Explain each of the seven scenarios that were run in Exhibit A-50, including the differences between the scenarios, and what is meant by "capacity price sensitivity," "high volatility" versus "Low volatility," and "short cycle' versus "long cycle."

Response:

a) The input data and input assumptions are voluminous and contain confidential and proprietary information. The Company will provide a copy of the model used, including the input data and input assumptions to parties that execute a suitable non-disclosure agreement.

b) The source of each input and assumption is voluminous and contain confidential and proprietary information. The Company will provide a list of the source of each input and assumption to parties that execute a suitable non-disclosure agreement.

c) The models used to produce the four exhibits are voluminous and contain confidential and proprietary information. Additionally, some input and output formats are subject to a non-disclosure agreement with the model supplier. The Company will provide a copy of the models used to produce the four exhibits to parties that execute a suitable non-disclosure agreement with the Company and are either licensed by the model supplier to use the proprietary software model, or have executed a suitable non-disclosure agreement with the model supplier, or both (depending on the type of report to be provided).

d) Exhibit A-48 (DFR-3) considers the system revenue requirements for years 2013 through 2040. Exhibit A-49 (DFR-4) considers system costs, emission allowance costs, variable O&M costs and net system costs for 2013, 2014, and 2015. Exhibit A-50 (DFR-5) considers system revenue requirements for years 2013 through 2040. Exhibit A-51 (DFR-6) considers energy generated for 2015.

e) The analysis provided in Exhibit A-48 (DFR-3) started in December 2011 and ended in March 2012. The analysis provided in Exhibit A-49 (DFR-4) was conducted in July 2012. The analysis provided in Exhibit A-50 (DFR-5) started in December 2011 and ended April 2012. The analysis provided in Exhibit A-51 (DFR-6) was conducted in August 2012.

f) The analysis provided in Exhibit A-48 (DFR-3) did not study the classic 7 generating units individually. The Company studied the units as an aggregate resource due to their similar size, age and technologies.

g) The analysis provided in Exhibit A-48 (DFR-3) only considered the incremental capital and O&M and Net System Revenue requirements for scenarios in which all seven generating units are removed from service as of January 1, 2015 as opposed to the otherwise assumed retirement for all seven units of December 31, 2025. The analysis did not consider various combinations of units removed from service at different dates. The Company considered this analysis as sufficient due the similar size, age and technologies of the seven generating units.

h) Not Applicable

i) The analysis in exhibit A-49 (DFR-4) did not study the classic 7 units individually. The Company studied the units as an aggregate due to their similar size, age and technologies.

j) The analysis provided in Exhibit A-49 (DFR-4) only considered the incremental capital and O&M and Net System Revenue requirements for scenarios in which all seven generating units are removed from service as of January 1, 2013 as opposed to the otherwise assumed retirement for all seven units of April 1, 2015. The analysis did not consider various combinations of units removed from service at different dates. The Company considered this analysis as sufficient due the similar size, age and technologies of the seven generating units.

k) Not Applicable

l) The analysis in exhibit A-50 (DFR-5) did not study the five generating units individually. The Company studied the units as an aggregate due to their similar size, age and technologies as well as the Net Present Value of

Net System Cost of early retirement.

m) The analysis provided in Exhibit A-50 (DFR-5) only considered the incremental capital and O&M and Net System Revenue requirements for scenarios in which all five generating units are removed from service as of January 1, 2015 as opposed to the otherwise assumed retirement date for Campbell Units 1 and 2 and Karn Units 1 and 2 of December 31, 2030 and for Campbell Unit 3 of December 31, 2050. The analysis did not consider various combinations of units removed from service at different dates. The Company considered this analysis as sufficient due the similar size, age and technologies of the five generating units as well as the Net Present Value of Net System Costs of early retirement.

n) Not Applicable

o) As of the filing date in this case, the Company had only conducted the studies presented in Exhibits A-50 (DFR-5) regarding the cost to remove the Big 5 generating units from service as of January 1, 2015. The Company continues to study scenarios regarding the operation of the Big 5 coal plants beyond 2015, however such studies are incomplete.

p) The scenarios in Exhibit A-50 (DFR-5) represent a different capacity price curve for each case. Line 1 of Exhibit A-50 (DFR-5) used the Company's then current capacity price assumption (price transitioning from current pricing to a price representing approximately 95% of the revenue requirements associated with construction of a new gas-fueled combustion turbine in 2015 and thereafter) to calculate the net present value of net system revenue requirements for early retirements and continued operation of the Big 5 coal plants assuming that all necessary capacity could be purchased at spot prices and assuming that only 1,000 MW of necessary capacity could be purchased at spot prices (with remaining capacity to be acquired through facility purchases or new installations). On Line 2 capacity price assumed was reduced to 75% of the then current capacity price assumption. Line 3 assumes capacity prices are reduced to 50% of the then current capacity price assumption. Line 4 assumes capacity prices fluctuate from year to year with an average price at about 75% of the then current capacity price assumption but ranging between 25% and 150% of the then current capacity price assumption on a 4 year cycle. Line 5 assumes capacity prices fluctuate from year to year with an average price at about 75% of the then current capacity price assumption but ranging between 25% and 150% of the then current capacity price assumption on an 8 year cycle. Line 6 assumes capacity prices fluctuate from year to year with an average price at about 75% of the then current capacity price assumption but ranging between 50% and 125% of the then current capacity price assumption on a 4 year cycle. Line 5 assumes capacity prices fluctuate from year to year with an average price at about

17087-MEC-CE-78
Page 5 of 5

75% of the then current capacity price assumption but ranging between 50% and 125% of the then current capacity price assumption on an 8 year cycle.

The following document provided:

1. Document titled [redacted].

David F. Ronk, Jr.
December 7, 2012

Transactions and Wholesale Settlements Department

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00161**

DIRECT TESTIMONY OF
CHARLES R. SCHRAM
DIRECTOR, ENERGY PLANNING, ANALYSIS AND FORECASTING
LG&E AND KU SERVICES COMPANY

Filed: June 1, 2011

2011 Air Compliance Plan

LG&E® KU®

PPL companies

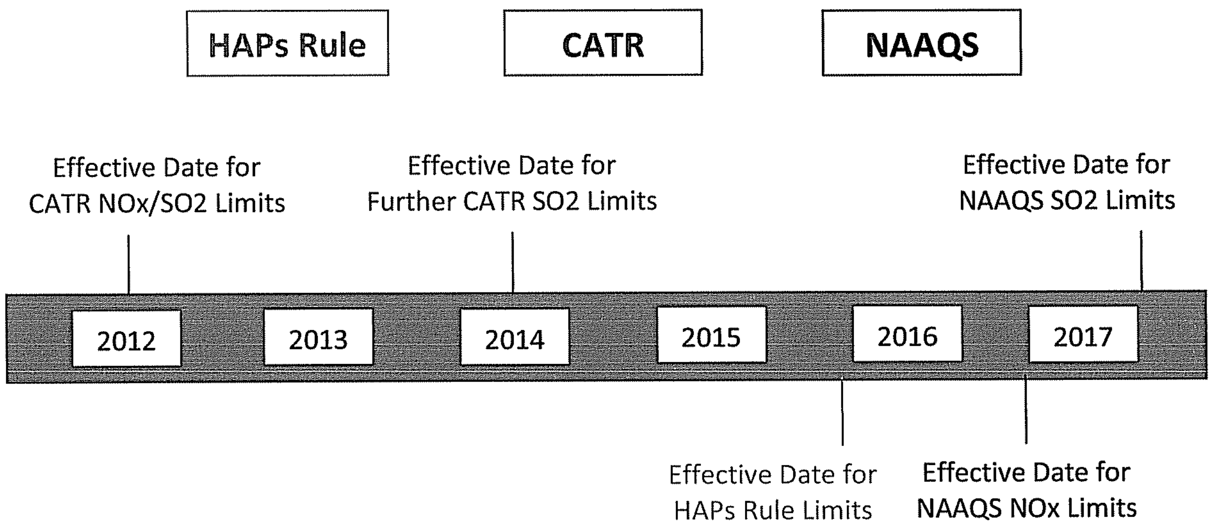
Generation Planning & Analysis
May 2011

Table of Contents

1.0 Executive Summary

In July 2010, the Environmental Protection Agency ("EPA") issued a proposed Clean Air Transport Rule ("CATR") that provides limited allowances for NO_x and SO_2 emissions starting in 2012. In March 2011, the EPA issued a proposed rule aimed at reducing hazardous air pollutants (such as mercury, other metals, acid gases, and organic air toxics, including dioxins) from new and existing coal- and oil-fired electric utility steam generating units ("HAPs Rule"). In addition to these proposed rules, the EPA's National Ambient Air Quality Standards ("NAAQS") will further restrict NO_x and SO_2 emissions beginning in 2016 and 2017. Key dates in the implementation of these regulations are summarized below in Figure 1.

Figure 1 – Environmental Regulations Timeline



To comply with the proposed regulations at each of its coal units, LG&E and KU (the "Companies") must either install additional emission controls or retire and replace the capacity. The process of determining the least-cost compliance plan consists of the following three tasks:

1. The Companies (in conjunction with Black & Veatch, an engineering consulting firm) developed construction cost estimates for the least-cost option for installing emission controls at each unit to comply with EPA regulations.
2. Where compliance with the aforementioned environmental regulations is not measured on a unit-by-unit basis (CATR and HAPs Rule), the Companies conducted an analysis to demonstrate the need for emission controls on a station- or system-wide basis.
3. After the need for controls was established and the total expenditures for each unit were determined, the Companies compared the revenue requirements of installing controls to the revenue requirements of retiring and replacing capacity.

The results of the needs assessment (task #2) are summarized in Table 1. The control technologies in Table 1 would be required to comply physically with the proposed environmental regulations.

The Companies also developed cost estimates for installing SCRs on the Brown 1, Brown 2, Ghent 2, Mill Creek 1, and Mill Creek 2 units. However, the needs assessment demonstrated that this equipment is not needed to comply with NAAQS or the CATR at this time.

Table 1 – Capital Costs for Environmental Controls

Unit	Control Technologies	Total Capital ($M)
Brown 1 & 2	Baghouse[1], SAM[2] Mitigation	228
Brown 3	Baghouse	118
Cane Run 4	FGD[3], SCR[4], Baghouse, SAM Mitigation	295
Cane Run 5	FGD, SCR, Baghouse, SAM Mitigation	310
Cane Run 6	FGD, SCR, Baghouse, SAM Mitigation	399
Ghent 1	Baghouse, SAM Mitigation/Economizer Modifications	164
Ghent 2	Baghouse, SAM Mitigation	165
Ghent 3	Baghouse, SAM Mitigation/Economizer Modifications	199
Ghent 4	Baghouse, SAM Mitigation/Economizer Modifications	185
Green River 3	CDS[5] Fabric Filter	45
Green River 4	CDS Fabric Filter	66
Mill Creek 1 & 2	FGD[6], Baghouse	666
Mill Creek 3	FGD, Baghouse, SAM Mitigation/Economizer Modifications	225
Mill Creek 4	FGD, SCR Upgrade, Baghouse, SAM Mitigation/Economizer Modifications	386
Trimble County 1	Baghouse	124
Tyrone 3	CDS Fabric Filter	45

The differences in present value of revenue requirements ("PVRR") between (a) installing controls and (b) retiring and replacing capacity are summarized in Table 2.[7] The decisions to install controls were evaluated on a unit-by-unit basis except for cases where the least-cost compliance alternative is to install one control on multiple units (i.e., Brown 1 and 2 and Mill Creek 1 and 2).

[1] The least-cost compliance plan for Brown 1-2 is to install one baghouse to be shared by Brown 1 and 2.
[2] Sulfuric acid mist.
[3] Flue gas desulfurization.
[4] Selective catalytic reduction.
[5] Circulating dry scrubber.
[6] The least-cost compliance plan for Mill Creek 1-2 is to install one new FGD to be shared by Mill Creek 1 and 2.
[7] The values in Table 2 are in 2011 dollars and based on a 30-year study period (2011-2040).

Table 2 – PVRR of Installing Controls vs. Retiring and Replacing Capacity ($M, $2011)

Unit(s)	Install Controls (A)	Retire/Replace Capacity (B)	Difference (A)-(B)
Tyrone 3	33,153	33,140	(13)
Green River 3	33,140	33,060	(80)
Brown 3	33,060	33,661	601
Cane Run 4	33,060	32,972	(88)
Cane Run 6	32,972	32,980	8
Brown 1-2	32,980	33,208	228
Cane Run 5	32,980	32,921	(58)
Ghent 3	32,921	33,836	914
Ghent 1	32,921	33,715	794
Green River 4	32,921	32,811	(110)
Mill Creek 4	32,811	33,671	859
Trimble County 1	32,811	33,804	993
Ghent 4	32,811	33,966	1,155
Mill Creek 3	32,811	33,567	756
Ghent 2	32,811	33,950	1,139
Mill Creek 1-2	32,811	33,833	1,022

The cases to install controls considered the capital and fixed operating and maintenance ("O&M") costs of the controls as well as the associated impact on total system production costs. The cases to retire and replace capacity considered the capital and fixed O&M savings associated with retiring a unit, the costs of installing and operating replacement capacity, and the overall impact of the modified generation portfolio on system production costs.

The least-cost plan for complying with the proposed environmental regulations includes installing additional environmental controls on the Brown, Ghent, Mill Creek, and Trimble County 1 coal units (see Table 2). Installing controls on the Green River, Tyrone, and Cane Run 4-5 coal units is not cost-effective. In the case of Cane Run 6, the difference in PVRR between installing controls and retiring the unit is negligible ($8 million). If the Companies install controls on Cane Run 6 and the PVRR of a future expenditure not contemplated in this analysis exceeds $8 million, installing controls is not the least-cost option. Because the likelihood of this occurring is considered high, the Companies do not recommend installing environmental controls on Cane Run 6. As a result, Cane Run 6, along with the Green River, Tyrone, and the other Cane Run coal units, will be retired when the regulations take effect.

The costs of the projects in the least-cost compliance plan are summarized in Table 3. The total capital cost for KU is $1,058 million. The total capital cost for LG&E is $1,400 million.

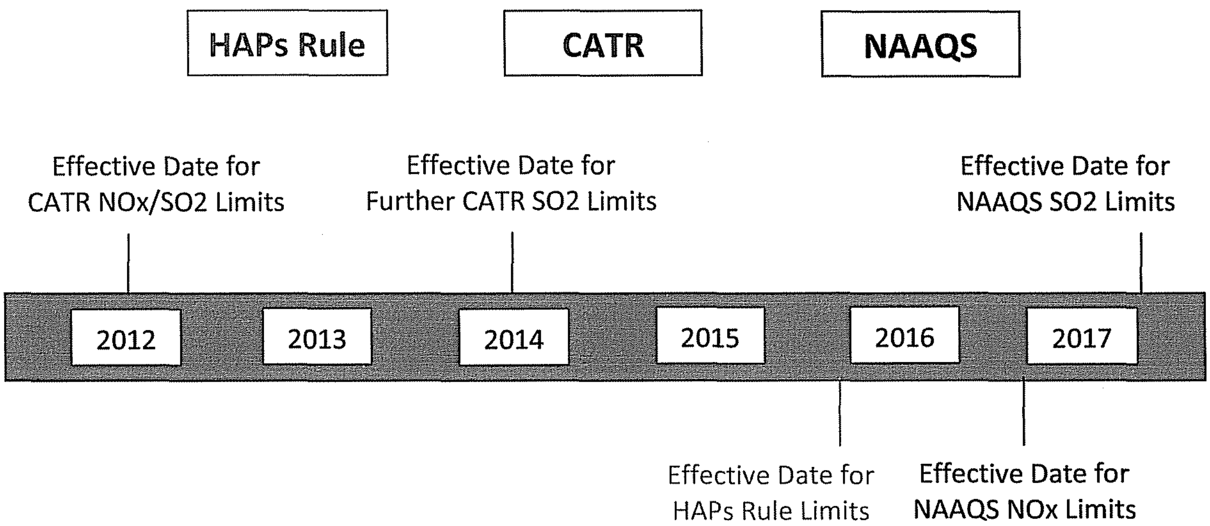
Table 3 – Proposed Capital Costs

Company	Generating Unit	Capital ($M)
KU	Brown 1-2	228
KU	Brown 3	118
KU	Ghent 1	164
KU	Ghent 2	165
KU	Ghent 3	199
KU	Ghent 4	185
KU	**Total**	**1,058**
LG&E	Mill Creek 1 -2	666
LG&E	Mill Creek 3	225
LG&E	Mill Creek 4	386
LG&E	Trimble County 1	124
LG&E	**Total**	**1,400**

2.0 Summary of Environmental Regulations

The EPA's National Ambient Air Quality Standard ("NAAQS"), Clean Air Transport Rule ("CATR"), and HAPs Rule are precipitating the need for additional emission controls over the next several years. Key dates in the implementation of these regulations are summarized below in Figure 2. Each of these regulations is discussed in more detail in the following sections.

Figure 2 – Environmental Regulations Timeline



2.1 National Ambient Air Quality Standard

The EPA's NAAQS places further restrictions on SO_2 and NO_x emissions beginning in 2016 and 2017. Unlike the proposed CATR and HAPs Rule, the NAAQS is final. Compliance with NAAQS emission limits are measured on a unit-by-unit basis. Table 4 summarizes the Companies' current (2010) SO_2 and NO_x emissions, as well as the NAAQS emission limits.

17087-MEC-CE-84 (partial)

Question:

35. Refer to the direct testimony of David Ronk:

a) At what electric prices are installing the planned AQCS on the Campbell and Karn units no longer cost effective?

b) Have the potential purchase, construction, and/or modification of generating units considered as alternatives to the capacity provided by the 7 Classics been considered or factored in any way into the evaluation of the economics of installing AQCS versus retiring one or more of the Big 5 units? If yes, describe in detail how, and produce any and all documents representing such evaluation. If not, explain why not.

c) Has the expansion of Midland Cogeneration Venture been considered or factored in any way into the evaluation of the economics if installing AQCS versus retiring one or more of the Big 5 units? If yes, describe in detail how, and produce any and all documents representing such evaluation. If not, explain why not.

d) Has the New Covert Generating Station been considered or factored in any way into the evaluation of the economics of installing AQCS versus retiring one or more of the Big 5 units? If yes, describe in detail how, and produce any and all documents representing such evaluation. If not, explain why not.

e) Has additional demand side management been considered or factored in any way into the evaluation of the economics of installing AQCS versus retiring one or more of the Big 5 units? If yes, describe in detail how, and produce any and all documents representing such evaluation. If not, explain why not.

Response:

a) The Company has not produced such a study.

b) No. Given the economic value and the amount of un-depreciated asset value of the five coal-fueled electric generating units, replacement of the five generating units with potential purchase, construction and/or modification of the generating units has not been considered at this time.

c) No. Given the economic value and the amount of un-depreciated asset value of the five coal-fueled electric generating units, replacement of the five generating units with an expansion of the Midland Coal Generation Venture Limited Partnership facility has not been considered at this time.

d) David Kehoe provides a response to this question.

e) No. Given the economic value and the amount of un-depreciated asset value of the five coal-fueled electric generation units, replacement of the five generating units with additional demand side management has not been considered at this time.

David F. Ronk, Jr.
November 26, 2012

Transactions and Resource Planning Department

17087-MEC-CE-84d (PARTIAL)

Question:

35.

d. Has the New Covert Generating Station been considered or factored in any way into the evaluation of the economics of installing AQCS versus retiring one or more of the Big 5 units? If yes, describe in detail how, and produce any and all documents representing such evaluation. If not, explain why not.

Answer:

35.

d. No, Consumers Energy has not evaluated the option identified in discovery question 17087-MEC-CE-84d.

As for why not, the primary reason is to maintain a balanced portfolio.

David B. Kehoe

David B. Kehoe
November 26, 2012

Electric Generation & Plant Operations

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times"

Susan Tierney
Analysis Group

Boston, Massachusetts
September 2009

This White Paper was prepared for the Electric Power Supply Association. This paper represents the views of the author, and not necessarily the views of Analysis Group, EPSA, or its members.

Allocating Investment Risk in Today's Uncertain Electric Industry:
A Guide to Competition and Regulatory Policy During "Interesting Times"

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Crisis: Danger and Opportunity[1]

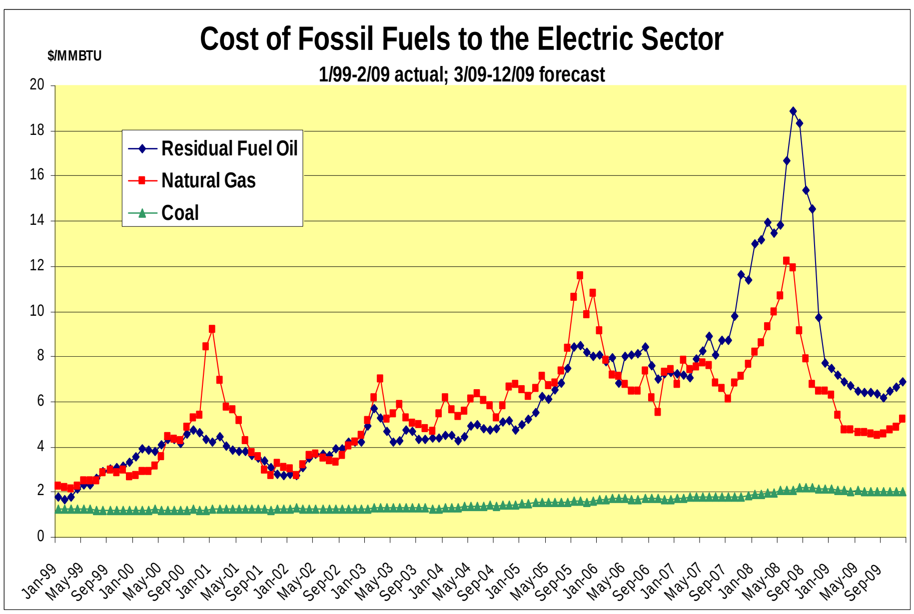
Introduction

It doesn't take a crystal ball to know that this is a rough and uncertain time. While no one ever knows how the future will unfold, the severity of today's economic crisis lends a particularly sobering quality to these unknowns.[2]

In the electric industry, this uncertainty creates substantial challenges. This is a notoriously capital-intensive industry – whether the funding goes toward power plant investments, transmission or distribution facilities, large-scale adoption of metering equipment, or installation of large numbers of new solar panels on building rooftops. Capital is committed by many entities including competitive generators, utilities and others. Regardless of who provides it, capital requirements can be daunting.

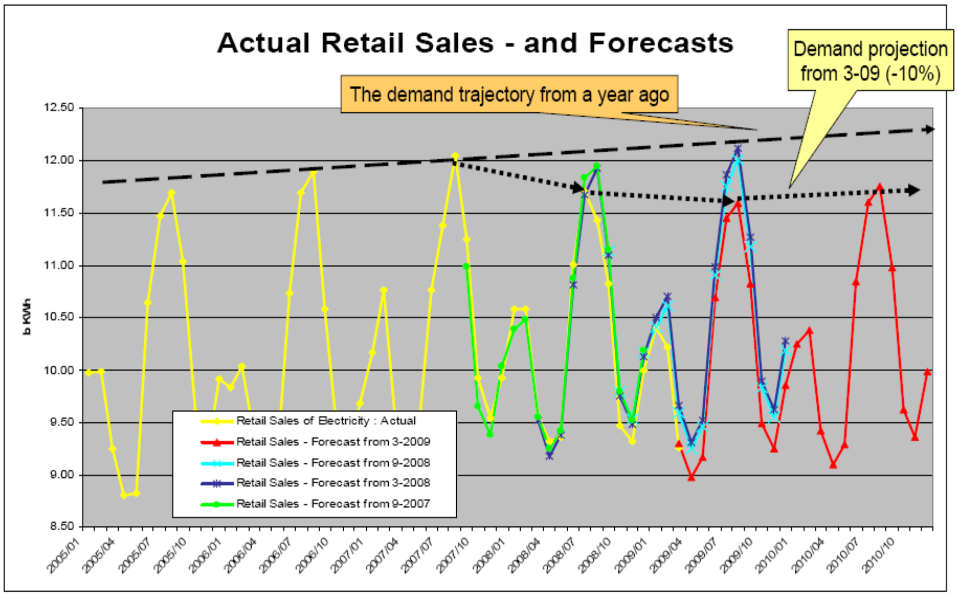
Knowing what type of investment to make is hard enough in more settled times. It is even harder given the various sources of uncertainty that abound at present:

- Will natural gas prices – and wholesale electricity prices in many regional markets – remain low, or rebound with global economic growth? (In the past year, the price of natural gas – which is used to produce one-fifth of the nation's power – rose to all-time highs as well as 5-year lows in the space of a few months.[3],[4])



Source: EIA[5]

- Will demand for electricity rebound after the current economic crisis begins to pass, or will the energy efficiency and demand-response measures promoted by the combined effects of the federal economic recovery program, state policy and programs of utilities and regional grid operators slow (or eliminate) increases in demand in upcoming years? (Forecasts of 2009 power use that were prepared in March 2009 show demand estimates 10 percent lower than forecasts prepared the year before.[6])



EIA, Electric Power Monthly data series; Short-Term Energy Outlook

- Will electric companies be able to fund new demand- or supply-side investments in light of balance sheet challenges,[7] current credit market conditions,[8] and traditional regulatory ratemaking policies[9] that need to adapt to today's realities?

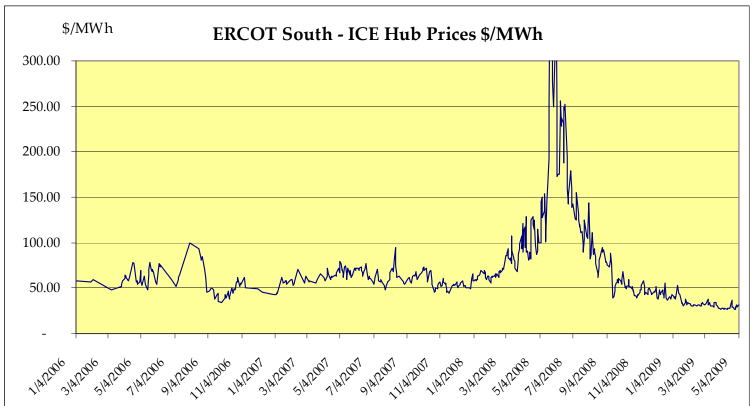
- What form will national carbon controls take by the time they impact the economy – given that their timing and shape are affected not only by congressional debates that are still underway[10] but also by countless implementation decisions that will need to be made over the years following passage of new legislation? Will its provisions create the right conditions to induce new low-carbon technologies into the market place?[11]

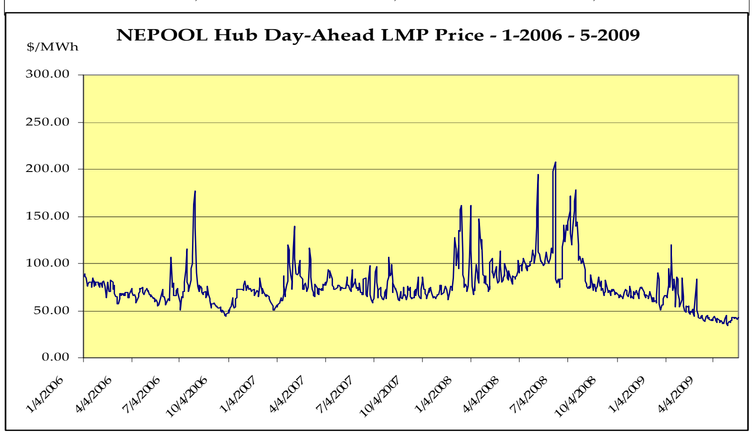
These are indeed "interesting times." As the Chinese say each time they use the word "crisis," this is both a challenging and opportune moment. President Obama referred to those challenges and opportunities when he spoke of the economy and the electric system on his inaugural day in January 2009,[12] and then again when he addressed a joint session of Congress a month later.[13] The American Recovery and Reinvestment Act is providing billions of dollars for investment in energy technologies. If the President accomplishes his goal, this will be a down payment towards larger changes in the electric industry, affecting demand for electricity, the robustness of the electric grid, and the ability of low-carbon and renewable technologies to move into markets.

These conditions pose a complicated set of options for electric companies and for regulators. How does one create an appropriate policy atmosphere in the face of so much risk and uncertainty?[*][14] An understandable response would be to retreat to the familiar. But what is safe ground in today's environment? I offer two suggestions for how regulators might approach these issues: First, ride the horse you're on (or, as Abraham Lincoln would say, don't change horses midstream). Second, extract the best from principles of competition and regulation.

Ride the horse you're on

In recent years, there have been debates in policy circles and in the industry more generally on whether those parts of the country that restructured their electric industry would be better off returning to a more traditional industry model. Although political pressure (especially among elected officials) to do so has ebbed somewhat with the decline in natural gas prices and the related drop in wholesale electricity prices, there are still rumblings in various corners about this issue. (See figures to the right, which illustrate the variation in electricity prices over the past several years, using Texas (ERCOT South) and New England (NEPOOL) as examples.)





Source: EIA, Wholesale Market Data, http://www.eia.doe.gov/cneaf/electricity/wholesale/wholesale.html, accessed on June 5, 2009.

[*] In a separate document ("Appendix Figures for the Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times" (September 2009), I have compiled information that compares historical forecasts of important variables (like demand, fuel prices, construction costs, and so forth) that affect investment decisions, with information about the actual trends in the variables of interest over time. Please see the EPSA website to review this separate appendix.

At this particularly turbulent time in our industry, it is more important than ever to do things to raise investor confidence in ways that will produce benefits to consumers. In this context, it is not helpful to keep debating the "markets versus regulation" question. All else equal, regulatory uncertainty and political risk will always put pressure on investor confidence. There is already enough uncertainty for all of us to deal with,[15] without adding to it by continuing to debate whether a state should dramatically alter the structure of its electric industry. That is why I suggest that each jurisdiction "ride the horse you're on" and then make good use of the policy tools of competition and regulation in order to provide the best sustainable, long-term outcomes to reliably serve consumers.

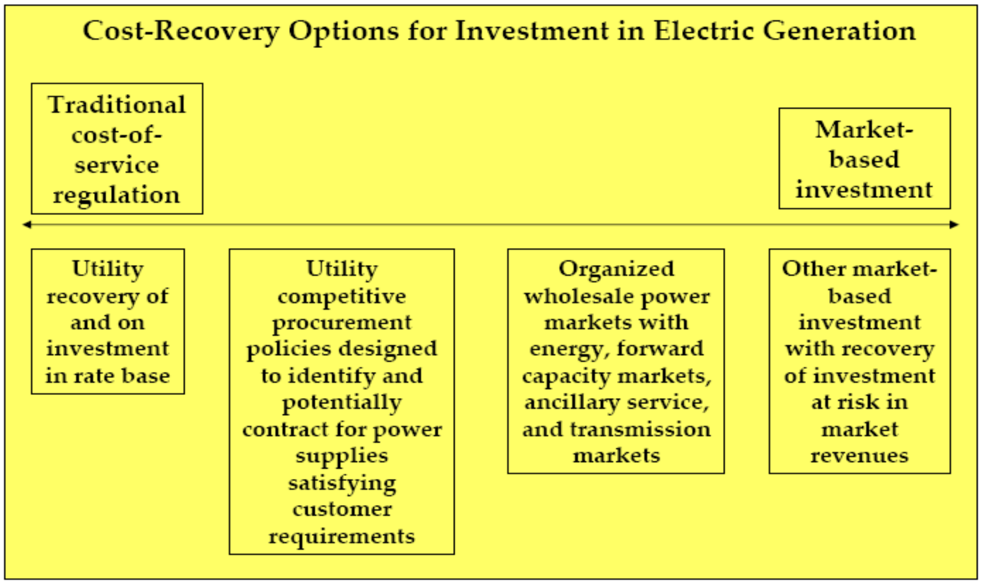
Extracting the best from competition and regulation

For many decades, the electric industry relied principally on traditional cost-of-service regulation. More recently, the industry has also incorporated a number of regulatory approaches built on competition. Many years of experience provide instructive lessons about why it is important to rely on the best of both market and regulatory mechanisms.

We know that it is important to structure both markets and regulation using sound policy design. On the traditional ratemaking side, we learned lessons from problems caused by after-the-fact prudency reviews of massive nuclear investments in the 1980s, and we are learning to align incentives with desired results as we move toward reliance on revenue decoupling as a companion to energy efficiency initiatives by utilities.[16] And in markets, we better understand the importance of market design after the California electricity crisis in 2000-2001, and as we see the benefits of competition for improved power plant performance,[17] and in the results of competitive power procurements.[18]

Continuing on a regulatory path that attempts to assign risks to those parties best suited to best manage them is a sound rock to stand on. This is hardly rocket science, but it is still worth remembering that this will give electricity customers the benefit of the best of both market-based approaches and regulation.

There are many examples of well-functioning market designs in the space between a pure traditional cost-of-service regulatory framework and a pure merchant model for generation investment. While there are various designs along the spectrum, there are two strong, well-functioning approaches in the middle: energy auctions administered by regional transmission organizations, and competitive solicitations carried out by load-serving entities such as electric utilities. Both operate pursuant to rules established by regulators. And both rely on competitive pressures on suppliers to discipline costs, and the oversight of regulators to ensure fair and open competition. In the following section, I review the two bookends and the two "middle" approaches.



These Four Cost-Recovery Options

The starting point for discussing these investment recovery options is to remember the importance of establishing appropriate regulatory incentives for disciplining costs. In well-performing markets, firms and individuals have incentives to reduce costs and make appropriate investments because they can realize the consequences of their decisions.

In the electric industry historically, regulation arose because various conditions[19] prevented reliance on market forces. Regulated cost-based rates serve as a second-best proxy for price in the absence of competitive markets.[20] In the presence of markets, we can shop around for what we consider to be the best deal, knowing that suppliers are competing with each other for our business.

Thus, the electric industry has two archetypal models for inducing power generation investments. On the one hand are power plant investments and operations under traditional cost-based, rate-of-return regulation of utilities; on the other hand, investments and operations of power plants occur under market-based rates. These are not the sole models for investment, but rather serve as "bookends" for other possible arrangements between investors, utilities, regulators, and third-party suppliers. In practice, many utilities use competitive markets as part of how they approach investments and operations under regulated rates.[21] And many third-party suppliers rely on contracts with regulated utilities as a fundamental element of the suppliers' ability to bring market-based products to fruition.[22]

Still, focusing on utility rate-base investment and merchant third-party market-based investment as two ends of the spectrum (shown in the figure above) allows us to examine important issues about how these alternative arrangements allocate the risks between the investor, the utility, the regulator, and the consumer. The different regulatory/ financial incentives involve the following elements:

- *Recovery of and on investment subject to regulatory approval*. Under this classic model, the utility undertakes an investment and construction program (with more or less regulatory review of its resource plans). As the project becomes ready to provide service to consumers, the utility seeks to include the new investment in rate base – and to charge customers rates that allow recovery of and on the investment. The regulators then perform an after-the-fact review of the prudency of the investment, and determine whether it is "used and useful." Having been approved by utility regulators, such new investment is folded into the utility's revenue requirement at the next rate case, and rates are set to recover these new costs (along with other costs in the new period).[23],[24]

- *Utility's Power Purchase Agreement with an Independent Supplier*. Instead of building its own power plant, a utility may contract for wholesale power supply from independent suppliers through a long-term agreement. Such agreements may arise from bilateral negotiations or competitive procurements. Many formal competitive procurements are subject to oversight and rules of regulators. By design, competitive procurements for incremental resources are intended to be the means by which a utility identifies the "best" resource option to satisfy a particular supply need (e.g., dispatchable intermediate supply, or peaking capacity, or renewable energy credits).[25] If the utility selects a third-party supply offer (as opposed to building its own plant), a contract between the utility and the supplier serves as the basis for allocating specific risks between the investor (the power supplier) and the utility (who buys the power). Typically, the costs associated with contracted-for supplies are recoverable in rates, often through a mechanism that passes costs through to consumers (as in a fuel-adjustment clause or similar cost-recovery mechanism). (Note that another form of competitive procurement exists in states with restructured electric industries with distribution companies without their own power supply; here, the utility may rely on competitive procurements to procure wholesale supply for basic service customers.)

- *Investment within Organized Wholesale Power Markets*. Some companies have been able to support investment in generation through their participation in various auctions in power markets administered by Regional Transmission Organizations ("RTOs"). Although the specific details of RTO-administered markets vary across regions, some (e.g., PJM, ISO-NE) involve a combination of markets (e.g., day-ahead and real-time energy markets, forward capacity markets, various ancillary service markets, transmission congestion contracts) that support plant investments. Some take the form of a financially binding long-term agreement (such as a multi-year transmission congestion contract, or a three-year forward capacity contract entered into as a result of a capacity auction), while others are structured in the way of short-term performance-based auctions (e.g., a financially binding day-ahead hourly energy auction).

- *Merchant Plant Development*. Under a pure merchant model, a third party (including in some cases a utility's unregulated affiliate) makes an investment in new generation facilities outside of a regulated cost-recovery framework. These investments are undertaken without the expectation of revenues obtained through regulated rates – whether through the utility's regulated ratebase, or through a contract that relies on recovery from a utility's customers, or through the regulated tariff of a regional transmission organizations). These investments may rely, however, on financial support or contractual commitments from unregulated retail providers,[26] or on the strength of the developer's/investor's balance sheet.

Allocating Risk – How It Works Under the Different Cost-Recovery Options

These various approaches involve different arrangements under which investment risk is borne by consumers.

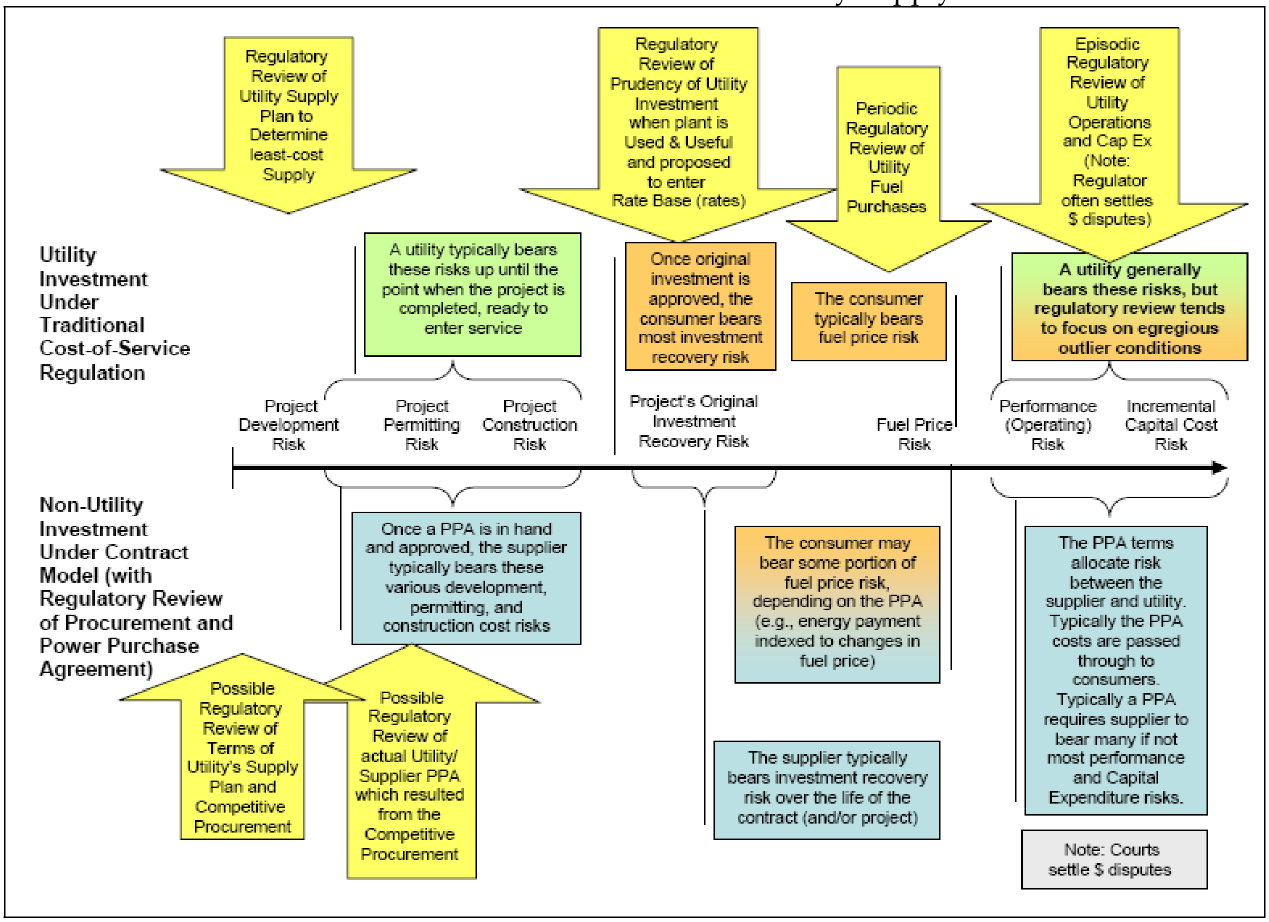
For example, after-the-fact review of utility power plant investments typically involves having the utility bear certain investment risks during the course of the planning, development and construction process. In the classic form of "prudency" reviews, the regulator assesses the utility's conduct after the fact, and uses adjudicatory proceedings to determine the extent to which appropriate and effective efforts were made by the utility to prudently manage such costs up to the point when the plant is ready to enter commercial operation and the utility seeks to recover investment costs in rates. While there are notorious examples of investment disallowances during the nuclear era, more commonly state and federal utility regulators have allowed utility investment into rates once it is used and useful.[27]

By contrast, a utility contract with a competitive supplier typically fixes the terms of payments and requires the supplier to bear many project risks, including development, permitting, construction-cost, and operating risk. Such agreements may allow certain elements of supplier compensation to vary over the life of the delivery of services under the contract, such as when construction payments are pegged to price indices that affect construction materials, or where energy prices are pegged to fuel price indices. Either way, because such contractual terms allow the third party supplier to retain profits from the reduction of costs, it typically provides an incentive to undertake efforts to lower these costs, and the supplier's original price was determined through a competitive process that yielded the lowest cost or best value to consumers. A performance-based contract can also insulate consumers from various risks associated with cost overruns and performance problems that might arise over construction and/or operations of the plant.

In both of these different approaches (e.g., rate basing of utility investment in plant, versus power purchase agreements between the utility and a supplier), regulators maintain oversight of any costs that may be recovered from ratepayers. Traditional cost-of-service review provides regulators with an on-going role in determining how the costs associated with the facility's construction and operation are passed through to consumers in rates, with difficult choices on whether to allow recovery of cost overruns by the utility when they occur.[28] Investment risk is usually settled at the time the utility presents the investment to regulators for approval to go into rates; regulatory treatment of operating costs, fuel cost and incremental capital expenditures for the facility may occur over the life of the unit. By contrast, utility purchase power agreements with suppliers attempt to fix the terms of payment in advance (e.g., prior to the delivery of third-party supply or the utility's investment); the regulatory review occurs at the time the utility presents the contract to the regulators for approval. This approach shifts substantial construction, fuel and operational risk away from consumers and therefore can provide important benefits to consumers given the many types of uncertainties facing the industry described earlier. Use of power purchase agreements does, however, involve some degree of mutual commitment on the part of regulators and utilities to live by the terms of potentially long-term agreements reached at the outset of a new investment. To be effective, the investor's commitment to bear the risks associated with project development must be matched by a corresponding commitment by the regulator to abide by the agreement regardless of external market outcomes – just as the third-party supplier is bound to the terms of any contract, for better or worse. Absent such regulatory commitment, the risk premiums required by investors to compensate for this regulatory risk may well offset the potential ratepayer gains from shifting project risks onto suppliers.

The choices among the alternative agreement structures involve important questions for regulators over the assignment of costs arising from particular infrastructure investments, and their ability to impose cost-discipline on and engage in risk sharing with utilities and third-party power suppliers. This is illustrated in the figure, below, which identifies and compares various risks for a traditional rate-based investment and an agreement for incremental supply from a 3rd-party supplier. These risks include a project's development, permitting and construction-cost risk; regulatory risk; risk of recovery of original investment; fuel price risk; plant performance (operating) risk; and incremental capital additions risk.

Comparison of Various Power Plant Investment and Operating Risks for a Traditional Rate-Based Investment and Third-Party Supply Contract



In practice, the appropriate cost-recovery and risk-allocation arrangements for a given resource and a given utility depends on many factors. Depending on the nature of the capital, operating and technology risks associated with a desired resource and the utility's existing portfolio of physical and financial assets, certain assignment of economic and financial risk may be more advantageous than others. There might be situations, for example, in which regulators determine that the presence of some type of profound risk and uncertainty would chill market participation in the absence of regulatory or other public policy decisions assigning to consumers the responsibility to bear some of this risk. This could occur for investment in certain advanced, capital-intensive, low-carbon technologies (such as a coal-fired integrated gasification combined cycle with or without carbon sequestration systems) which may involve technology, construction and operating risks that third-party suppliers are unwilling to undertake (or willing to undertake only at a price unacceptable to regulators). In such a case, the policy maker – whether a legislature or a regulator – might decide that it is important to include some mechanism by which consumers bear some of this risk.[29] This could take the form of a market-based approach for procuring renewables (or renewable energy credits), with regulators determining the amount to purchase and the market determining the lowest-cost means to accomplish it. Thus, the variety of agreements structures depicted in the figures above provides regulators with significant flexibility in how they encourage needed infrastructure investments.

It is important for regulators to recognize, however, that risk-sharing can be achieved through arrangements between consumers and third-party suppliers, as well as the more traditional risk-sharing between consumers and utilities. For example, if regulators determined that consumers should bear certain technology risk, then the option to supply resources with that attribute and risk profile could be made available equally to the utility and to third parties.

Similarly, it may be useful for regulators to avoid prescribing certain types of agreement structures, so that third party suppliers can compete for the opportunity to supply and offer alternative agreement structures that they believe can provide the utility and its customers with the best value. Thus, properly structured and independently evaluated competitive procurements provide a constructive means to determine prudent resource outcomes for consumers. Competitive processes provide an important mechanism that allows the market to make offers with different risk sharing arrangements while still providing regulators with continued oversight of resource needs and decisions.

Closing observations

This focus on incentives is a reminder of the importance of market forces in disciplining costs. Increases in output and performance by generating facilities whose operation has shifted from regulated to competitive markets attest to the potential of market forces to lower costs in the electricity industry. This is not to say that markets operate perfectly – something that the current capital market crisis makes abundantly clear. They need attentive oversight and regulation to assure that they are functioning well. But well-functioning competitive processes provide valuable attributes – choice, innovation, cost discipline, service quality, and so forth – which together provide benefits to consumers regardless of the overall regulatory structure of a particular jurisdiction. It is using these competitive mechanisms in conjunction with strong regulatory oversight that I believe is the best path forward in these uncertain and "interesting" times.

End Notes[30]

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[1] Apologies to Victor Mair, of the University of Pennsylvania, who explains that the Mandarin character for "crisis" is not intended to be the same as "danger + opportunity" even though "crisis" is composed of two characters whose separate meanings are "danger" and "opportunity." http://www.pinyin.info/chinese/crisis.html.

[2] See N. Gregory Mankiw, "Economic View: That Freshman Course Won't Be Quite The Same," *The New York Times*, May 24, 2009. As Mankiw explains, "the teaching of basic economics will need to change in some subtle ways in response to recent events," including "the challenge of forecasting. It is fair to say that this crisis caught most economists flat-footed. In the eyes of some people, this forecasting failure is an indictment of the profession. But that is the wrong interpretation. In one way, the current downturn is typical: Most economic slumps take us by surprise. Fluctuations in economic activity are largely unpredictable." www.nytimes.com/2009/05/24/business/economy/24view.html?ref=todayspaper, accessed May 24, 2009.

[3] High prices of $10.82 per mcf (in June 2008) and $10.62 per mcf (in July 2008) exceeded the prior record-breaking prices in the months following Hurricanes Katrina and Rita ($10.33/mcf in September 2008, and $9.89/mcf in October 2008). Prices in November 2008 ($5.97/mcf), December 2008 ($5.87/mcf) and January 2009 ($5.15/mcf) were the lowest same-month prices since 2003. EIA Monthly wellhead price of natural gas, 1-1-00 through 1-1-09, in $ per mcf.

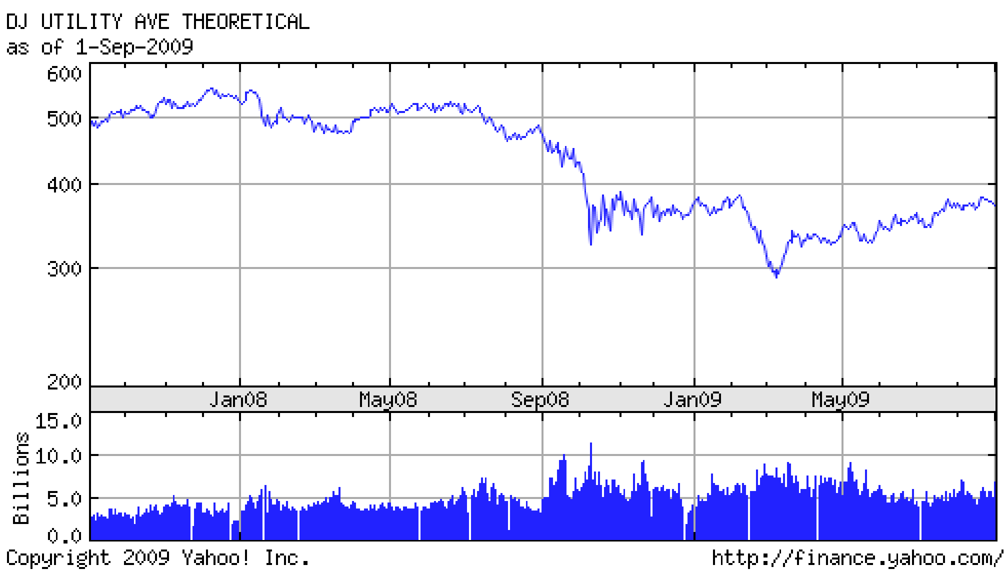
[4] Also, last year's estimate of the average price of natural gas in 2009 was more than double the estimate made a year later. For example, the estimate for the average price of natural gas to the electric sector was $9.15 per MMBtu (as estimated in May 2008) and $4.30 per MMBtu (as estimated in May 2009). EIA, Short-Term Energy Outlooks, Table 7.a.

[5] EIA, Short Term Energy Outlook Data Tables, http://www.eia.doe.gov/emeu/steo/pub/xls/STEO_m.xls (March 2009)

[6] The forecasts of electricity use in 2009 that were prepared during the Spring of 2009 show projections 10 percent lower than forecasts prepared as recently as a year before. In the figure, the forecast for 2009 prepared as of 3-2009 (shown in red) is 11-12 percent lower than the forecast for 2009 prepared one year previously (shown in blue). During the year ending 3/2009, retail sales were 2 percent lower than during the year ending 3/2008, and 5 percent lower than during the year ending 3/2006. See EIA, Monthly Electric Sales, from April of one year to the end of March of the following year (i.e., April 2000 through March 2008, and April 2008 through March 2009).

Further, in its most recent assessment for the summer months of 2009, the North American Electric Reliability Corporation ("NERC") made the following observations: "Decreased economic activity across North America is primarily responsible for a significant drop in peak-demand forecasts for the 2009 summer season…. Compared to last year's demand forecast, a North American-wide reduction of nearly 15 GW (1.8 percent) is projected. In addition, summer energy use is projected to decline by over 30 Terawatt hours (TWh), trending towards 2006 summer levels. While year-over-year reduction in electricity use is not uncommon — industrial use of electricity has declined in 10 of the past 60 years [fn in original], for example — it is critical that infrastructure development continues despite this decline. Based on the information provided as part of this assessment, most Regions have not yet experienced adverse impacts on infrastructure projects. However, WECC has indicated that some generation and transmission projects have been deferred or cancelled, in part due to overall economic factors…." (NERC, Summer Assessment 2009, pages 1-3.)

[7] During one week alone in the Fall of 2008, electric industry securities lost a third of their value. The Dow Jones Utility Average index fell from 486.14 on August 28, 2008, to 324.57 on October 10, 2008, a decline of 34 percent in the overall market capitalization of the electric companies tracked by this index. (During this same period, the Standard & Poor's 500 Index fell more than 30 percent – from 1,300.68 to 899.22 between August 28 and October 10.) The changes happened against a 12 month high of 552.74 in December 10 2007. Prices declined again in March 2009 to a low of 296.89,, but have rebounded somewhat since then. The index had a value of 367.26 on September 2, 2009. http://finance.yahoo.com/q?s=%5EDJU



[8] Capital markets are quite constrained due to the financial crisis facing the country. There are fewer financing options available and accessing capital has become more expensive. Utility companies' credit ratings are dropping, with a higher percentage of downgrades to upgrades in the past year. (See, for example, S. Bonelli, Fitch Ratings, presentation to the Energy Bar Association, April 23, 2009.) In addition, tight credit markets have been significantly tougher for companies with poorer credit ratings. While widening credit spreads (e.g., the difference between bond yields and yields for 10-year treasury notes) have been particularly dramatic for bonds issued by companies with poorer credit ratings, they have been significant for all companies regardless of their credit-worthiness.

[9] Examples of utility regulatory policies that are undergoing change include:

- Adoption of revenue decoupling for utilities whose revenues are affected by the adoption of cost-effective energy efficiency ("EE") measures. ("[E]ncouraging or mandating demand-side EE schemes without shielding the electric utility sector from financial harm is becoming an increasingly important credit issue due to the potential for decreased sales revenues and recovery or authorized costs. Historically, traditional rate design generally resulted in higher utility profits when energy sales increased, and lower utility profits when sale dropped. Amid the current recession and the significant increase in federal spending on EE, we believe that utility sector credit quality may benefit from regulatory and public policy that addressed concerns over cost under recovery. Provisions like decoupling mechanisms may untie or lessen the correlation between a utility's profits and energy sales, mitigating potential utility financial risks." Tony Bettinelli, "When Energy Efficiency Means Lower Electric Bills, How Do Utilities Cope?" Standard & Poor's RatingsDirect, March 9, 2009.)

- Use of competitive procurement approaches for arranging supply for retail electricity customers. (See Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.)
- Use of long-term contracts and renewable portfolio standards to support investment in renewable energy generating facilities. (See: New York Independent System Operator, response to Question 15, http://www.nyiso.com/public/webdocs/newsroom/whats_new/ResponsetoBrodskyCahillCompleteDocument.pdf.)
- Reliance on various capital-expenditure adjustment mechanisms and reliance of future test years (See Edison Electric Institute's 2008 Financial Review (Plus 2009 Developments), Annual Report of the U.S. Shareholder-Owned Electric Utility Industry," http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/Financial_Review_full.pdf.)
- Adoption of forward capacity markets in Regional Transmission Organizations (see, for example, http://www.epsa.org/forms/uploadFiles/FE8800000177.filename.FYI-4_Policy_ Paper -_Essential_Elements_Final.pdf)

These are but a few of the approaches that are in discussion – and in use in many parts of the country.

[10] As of this writing, the House has approved H.R. 2454, "The American Clean Energy and Security Act." As described on the Committee's website, "This legislation is a comprehensive approach to America's energy policy that charts a new course towards a clean energy economy." The House bill differs in many respects from parallel bills currently introduced in the Senate.

[11] There are debates in the literature about whether a new carbon cap-and-trade program that is able to make it through Congress in the near term will produce greenhouse gas allowance prices high enough to induce investment in advanced technologies (e.g., advanced coal-fired generation with carbon capture and sequestration) that are capital intensive, emit low greenhouse gases and still not fully commercial viable. See, for example, National Commission on Energy Policy, "Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges," December 2004, http://www.energycommission.org/ht/a/GetDocumentAction/i/1088; Constantine Samaras, Jay Apt, Ines L. Azevedo, Lester B. Lave, M. Granger Morgan, and Edward S. Rubin, "Cap and Trade is Not Enough: Improving U.S. Climate Policy," March 2009. http://www.epp.cmu.edu/httpdocs/ Publications/ClimatePolicy.pdf.

[12] Speaking of the entire country's situation during his Inaugural address in January 2009, President Obama said, "That we are in the midst of crisis is now well understood.... Our economy is badly weakened, …and each day brings further evidence that the ways we use energy strengthen our adversaries and threaten our planet….The state of the economy calls for action, bold and swift, and we will act — not only to create new jobs, but to lay a new foundation for growth. We will build the roads and bridges, the electric grids and digital lines that feed our commerce and bind us together. … We will harness the sun and the winds and the soil to fuel our cars and run our factories. … All

this we can do. All this we will do." Text of President Barack Obama's inaugural address on Tuesday, as delivered, *by The Associated Press* The Associated Press Tue Jan 20, 5:04 pm ET.

[13] "We know the country that harnesses the power of clean, renewable energy will lead the 21st century. And yet, it is China that has launched the largest effort in history to make their economy energy efficient. We invented solar technology, but we've fallen behind countries like Germany and Japan in producing it. New plug-in hybrids roll off our assembly lines, but they will run on batteries made in Korea. … It is time for America to lead again. Thanks to our recovery plan, we will double this nation's supply of renewable energy in the next three years. … We will soon lay down thousands of miles of power lines that can carry new energy to cities and towns across this country. And we will put Americans to work making our homes and buildings more efficient so that we can save billions of dollars on our energy bills. But to truly transform our economy, protect our security, and save our planet from the ravages of climate change, we need to ultimately make clean, renewable energy the profitable kind of energy. So I ask this Congress to send me legislation that places a market-based cap on carbon pollution and drives the production of more renewable energy in America. …" Remarks of President Barack Obama – As Prepared for Delivery - Address to Joint Session of Congress, Tuesday, February 24th, 2009. http://www.whitehouse.gov/the_press_office/remarks-of-president-barack-obama-address-to-joint-session-of-congress/.

[14] On February 17, 2009, President Obama signed into law H.R. 1, the American Recovery and Reinvestment Act of 2009 (the "Act").

[15] To underscore the array of uncertainties and forecasting challenges that affect decision-making in the industry, here is a list of several of the variables that routinely make investment decisions quite difficult:

- demand forecasting, given different economic outlooks and assumptions about both the penetration of electricity-using equipment and the effects of energy efficiency measures;
- fuel price forecasting, especially for fossil fuels;
- estimation of capital costs of different technologies, including not only large central-station generating plants (such as nuclear, advanced coal, centralized solar facilities) as well as renewable energy and distributed generating units (e.g., off-shore wind, roof-top solar);
- projecting performance characteristics (e.g., heat rates, construction costs, environmental emissions, availability of manufacturers' guarantees) of advanced technologies not yet ready for commercialization;
- forecasting the effect of regulatory and policy change, especially relating to environmental requirements and non-traditional cost-recovery ratemaking mechanisms;
- future price of emissions allowances;
- on-peak reliability value and potential capacity factors of various technologies (e.g., advanced nuclear, wind, solar, coal with carbon capture and sequestration); and
- siting attitudes towards particular facilities (e.g., nuclear projects, coal plants, wind farms, transmission facilities, carbon sequestration projects).

Additionally, in today's credit markets, there is the added risk of highly constrained access to and cost of capital. Many of these variables are discussed in more detail in the companion appendix document to this white paper ("Appendix Figures for the White Paper: Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During 'Interesting Times,'" September 2009), which can be found on the EPSA website.

[16] "The desire of reward is one of the strongest incentives of human conduct; …the best security for the fidelity of mankind is to make their interest coincide with their duty." Alexander Hamilton, The Federalist Papers (essay series), 72, 21 March 1788.

[17] For example, *see* Matthew Barmack, Edward Kahn and Susan Tierney, "A Cost-benefit Assessment of Wholesale Electricity Restructuring and Competition in New England," *Journal of Regulatory Economics*, May 12, 2006; Kira Fabrizio, Nancy Rose and Catherine Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency," *American Economic Review*, Volume 97, No. 4, September 2007. See also, http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/Power_Plant_Efficiency_Improved_with_Competition_04202009.pdf.

[18] See Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.

[19] These historical "natural monopoly" conditions included economies of scale in distribution systems, where it was inefficient for multiple firms to install and operate parallel power lines on city streets and in large urban systems. As a consequence, monopoly firms could provide service more efficiently that a competitive market. In such a situation, regulation was viewed as essential to curb a monopoly's natural inclination to abuse its market power. Over the last quarter of the 20th century, economic and technological changes in the generation portion of the electric industry eroded the natural monopoly conditions in the generation portion of the market.

[20] In the absence of markets – as occurs with regulated monopolies – the rate established by regulators serves as a proxy for price, with regulated rates serving to create prices that, to the extent possible, reflect those that would arise from a competitive market.

[21] Some utilities make investments under "performance-based rates," which provides certain incentives for utilities to reduce cost. Even in most jurisdictions with performance-based rates, however, regulators and utilities still tend to rely on a model that places prudent, used and useful investment in rate base with the prospects of recovery of and on that investment through regulated rates. And even where utilities are entering into power plant investments for which they seek to receive traditional cost recovery (e.g., through inclusion of prudently incurred investment in rate base and through recovery of expenses associated with operating power plants in cost-based rates), they may use various markets and binding contracts with third parties to provide goods and services they need to provide service to consumers. When viewed most broadly, such competitively solicited contracts may include agreements with equipment suppliers or construction contractors, fuel supply agreements, and so forth.

[22] For example, many independent power producers have relied upon the existence of a power purchase agreement signed with a utility as a critical element of the package provided to prospective lenders to demonstrate the financial viability of their projects and to qualify for debt financing. The lenders have tended to view such contracts as lowering project risk, especially in light of a body of utility and contract law, utility regulation and court decisions that has substantially allowed for the recovery of the costs associated with such 3rd-party supply contracts by the utility in rates charged to consumers.

[23] Note that there are instances where utility regulators review a utility proposal "before the fact." In these circumstances, the commission may review the question of whether the proposed project is needed and is least cost, whether to allow cost recovery, or both.

[24] Performance-based ratemaking with compensation tied to outcomes of interest to consumers. Some jurisdictions set rates for utilities under an approach designed to create incentives for the utility to conduct its utility business in an efficient fashion. This is accomplished by establishing a multi-year rate plan with periodic formulaic adjustments in rates. The rate adjustments are designed to create incentives for cost reduction by allowing the utility to share savings with consumers. Going forward, rates are then set pursuant to a schedule of planned adjustments tied to external benchmarks (such as changes in Consumer Price Index or other metrics). The rate plan serves as the framework through which shareholders and ratepayers both absorb risk.

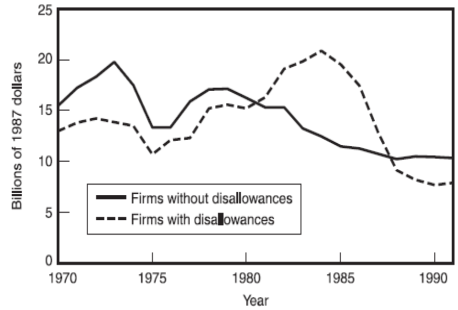
[25] For a more detailed discussion of best practices in competitive procurements, see: Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.

[26] For example, in Texas many competitive retail suppliers enter into bilateral contracts with generators to provide power supply.

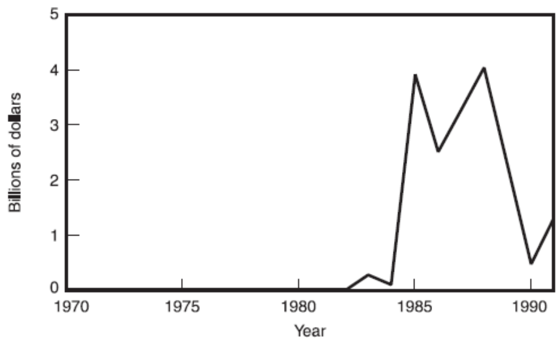
[27] "Major cost disallowances by regulators of public utility investments have always been a possibility. In the mid-1980s, however, this possibility came to life in the form of roughly $19 billion of disallowances of electric power plant investments that would otherwise have become part of the utilities' rate bases….Cost disallowances have typically occurred within the context of establishing the utility's rate base. The bulk of these disallowances have been categorized under the heading of management imprudence, but major disallowances have also occurred on the basis of excess capacity (which is not used and useful), and of economic value (in retrospect, alternative sources of power would have been cheaper). …It was not until the mid-1980s that significant dollar volumes of cost disallowances began to occur in the electric utility industry.[footnote in the original]. Typical disallowances during the mid-1980s amounted to hundreds of millions of dollars, and in two cases (the Nine Mile Point 2 unit in New York and the Diablo Canyon plant in California) regulatory cost disallowances were $2 billion or greater.[footnote in the original]. … [W]e see that virtually all regulatory cost disallowances occurred beginning in the mid-1980s. Cumulatively, over 50 separate disallowances on 37 different generating units were observed in the sample period, with a total dollar volume of disallowance of over $19 billion.[footnote in the original]." Thomas P. Lyon, and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," RAND Journal of Economics, Vol. 36, No. 3, Autumn 2005, pages 628–644. Figures from the Lyon/Mayo article (pages 630-633):

Real Investment by Electric Utilities, 1970–1991

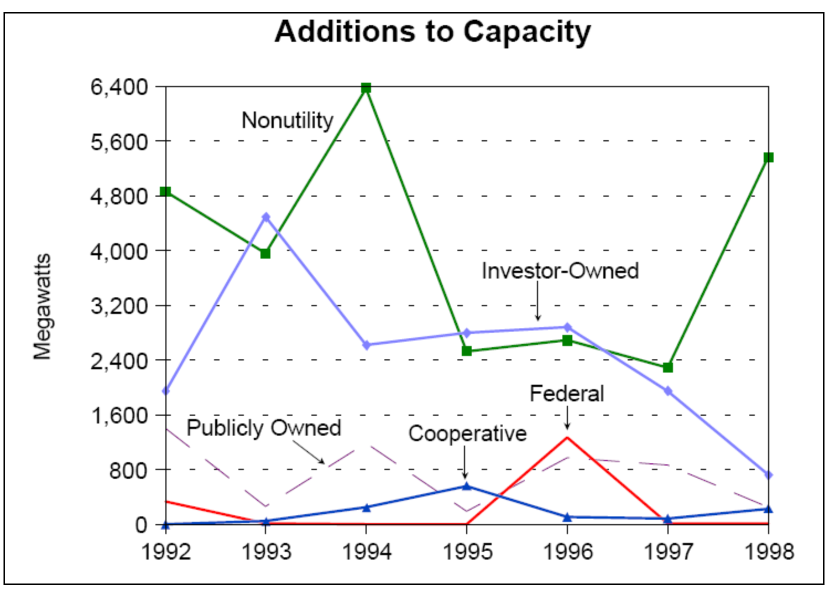
All Firms Real Investment by Electric Utilities, 1970–1991, By Firm Type



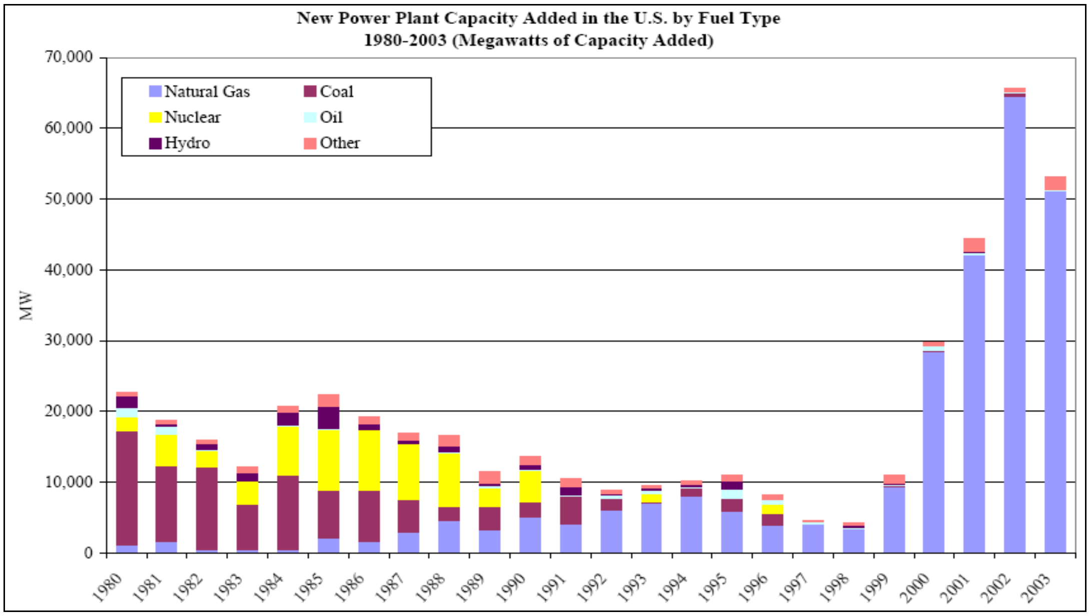
Dollar Values of Regulatory Disallowances, 1970–1991



[28] As noted by Lyon and Mayo, most of the costs that have been disallowed by regulators occurred during the past nuclear investment period. During the 1990s, and following upon the period of nuclear investment disallowances by regulators, most of the generating capacity that was added was done by non-utility generators. (See figure below for the Additions to Capacity (U.S.) during most of the 1990s. Source of figure: EIA, "The Changing Structure of the Electric Power Industry 2000: An Update," October 2000, page 25.)



Most capacity added from 1998 to mid-2000s was natural-gas plants added by non-utility companies (see figure showing megawatts of capacity added by fuel type by year, including during the years of major nuclear additions (and disallowances) in the 1980s):



Source: Tierney, using Platts Basecase data.

[29] A clear example of the former can be found in the loan guarantee provisions of the Energy Policy Act of 2005. Title XVII's Loan Guarantee Program authorizes federal loan guarantees to be issued for projects with new or significantly improved technologies that avoid, reduce or sequester air pollutants and that are proposed by sponsors providing a reasonable assurance of repayment. Another example is Iowa's law that allows the Iowa Public Utility Commission to authorized regulators to determine the ratemaking treatment of costs of projects before construction begins. Norman Jenks, "Another perspective: The importance of being certain," *Electric Perspectives*, May/Jun 2003, http://findarticles.com/p/articles/mi qa3650/is_200305/ ai_n9172919/.

[30] Susan Tierney is a Managing Principal at Analysis Group, Inc., in Boston, where she is an expert on energy policy, regulation and economics and focuses on the electric and gas industries. A consultant for a 14 years, she previously served as the Assistant Secretary for Policy at the Department of Energy (appointed by President Clinton), Massachusetts Secretary of Environmental Affairs (appointed by Governor Weld), Commissioner at the Massachusetts Department of Public Utilities (appointed by Governor Dukakis), and director of the Massachusetts Energy Facilities Siting Council. She recently co-led the Department of Energy Agency Review Team for the Obama/Biden Transition. She taught at the University of California at Irvine, and earned her Ph.D. and Masters degrees in regional planning at Cornell University. She has consulted to clients in business, industry, government, non-profit and other organizations. She serves on a number of boards of directors and advisory committees, including the National Commission on Energy Policy; chair of the Board of the Energy Foundation; a director of the Climate Policy Center/Clean Air-Cool Planet; member of the Advisory Council of the National Renewable Energy Laboratory, the Environmental Advisory Council of the New York Independent System Operator, and the WIRES' Blue Ribbon Commission on Transmission Cost-Allocation.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

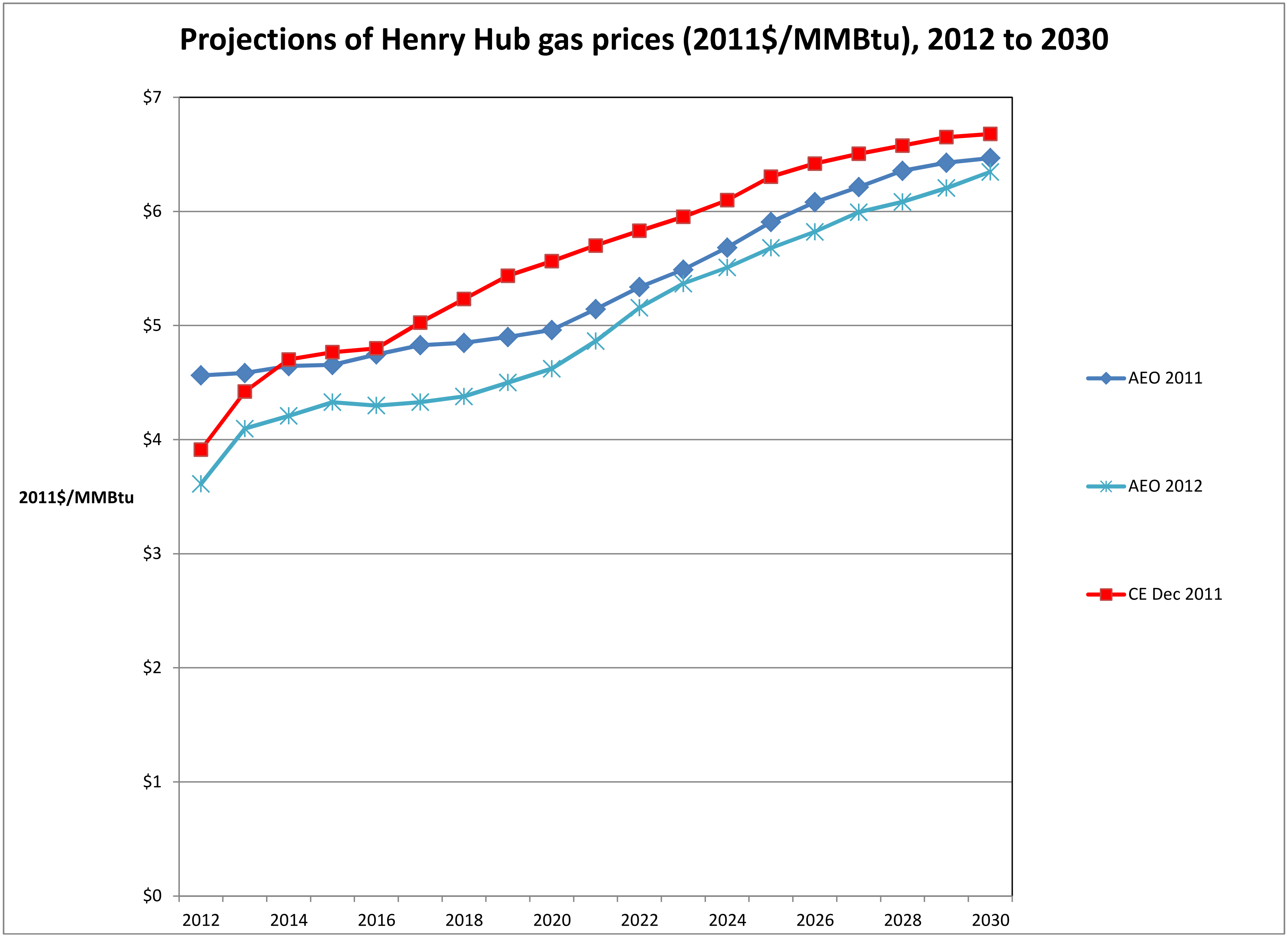
Supply, disposition, and prices	Reference case							Annual growth 2010-2035 (percent)
	2009	2010	2015	2020	2025	2030	2035	
Production								
Dry gas production[1]	20.58	21.58	23.65	25.09	26.28	26.94	27.93	1.0%
Supplemental natural gas[2]	0.07	0.07	0.06	0.06	0.06	0.06	0.06	-0.2%
Net imports	**2.68**	**2.58**	**1.73**	**0.35**	**-0.79**	**-0.89**	**-1.36**	**- -**
Pipeline[3]	2.26	2.21	1.56	1.01	-0.13	-0.27	-0.70	- -
Liquefied natural gas	0.42	0.37	0.16	-0.66	-0.66	-0.62	-0.66	- -
Total supply	**23.32**	**24.22**	**25.45**	**25.50**	**25.55**	**26.11**	**26.63**	**0.4%**
Consumption by sector								
Residential	4.78	4.94	4.85	4.83	4.76	4.72	4.64	-0.2%
Commercial	3.12	3.20	3.33	3.43	3.44	3.52	3.60	0.5%
Industrial[4]	6.17	6.60	7.01	7.08	7.14	7.03	7.00	0.2%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	6.87	7.38	8.08	7.87	7.87	8.47	8.96	0.8%
Transportation[8]	0.04	0.04	0.06	0.08	0.11	0.14	0.16	5.9%
Pipeline fuel	0.60	0.63	0.67	0.66	0.66	0.66	0.67	0.2%
Lease and plant fuel[9]	1.28	1.34	1.39	1.51	1.53	1.55	1.60	0.7%
Total	**22.85**	**24.13**	**25.39**	**25.47**	**25.53**	**26.10**	**26.63**	**0.4%**
Discrepancy[10]	**0.47**	**0.10**	**0.05**	**0.04**	**0.02**	**0.01**	**-0.00**	**- -**
Natural gas prices								
(2010 dollars per million Btu)								
Henry hub spot price	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
Average lower 48 wellhead price[11]	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
(2010 dollars per thousand cubic feet)								
Average lower 48 wellhead price[11]	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Delivered prices								
(2010 dollars per thousand cubic feet)								
Residential	12.25	11.36	10.56	11.11	12.33	13.08	14.33	0.9%
Commercial	10.06	9.32	8.82	9.21	10.27	10.86	11.93	1.0%
Industrial[4]	5.47	5.65	5.00	5.25	6.19	6.73	7.73	1.3%
Electric power[7]	4.97	5.25	4.65	4.83	5.73	6.35	7.37	1.4%
Transportation[12]	14.52	13.53	12.71	12.81	13.62	14.02	14.87	0.4%
Average[13]	**7.55**	**7.33**	**6.60**	**6.93**	**7.93**	**8.50**	**9.52**	**1.1%**

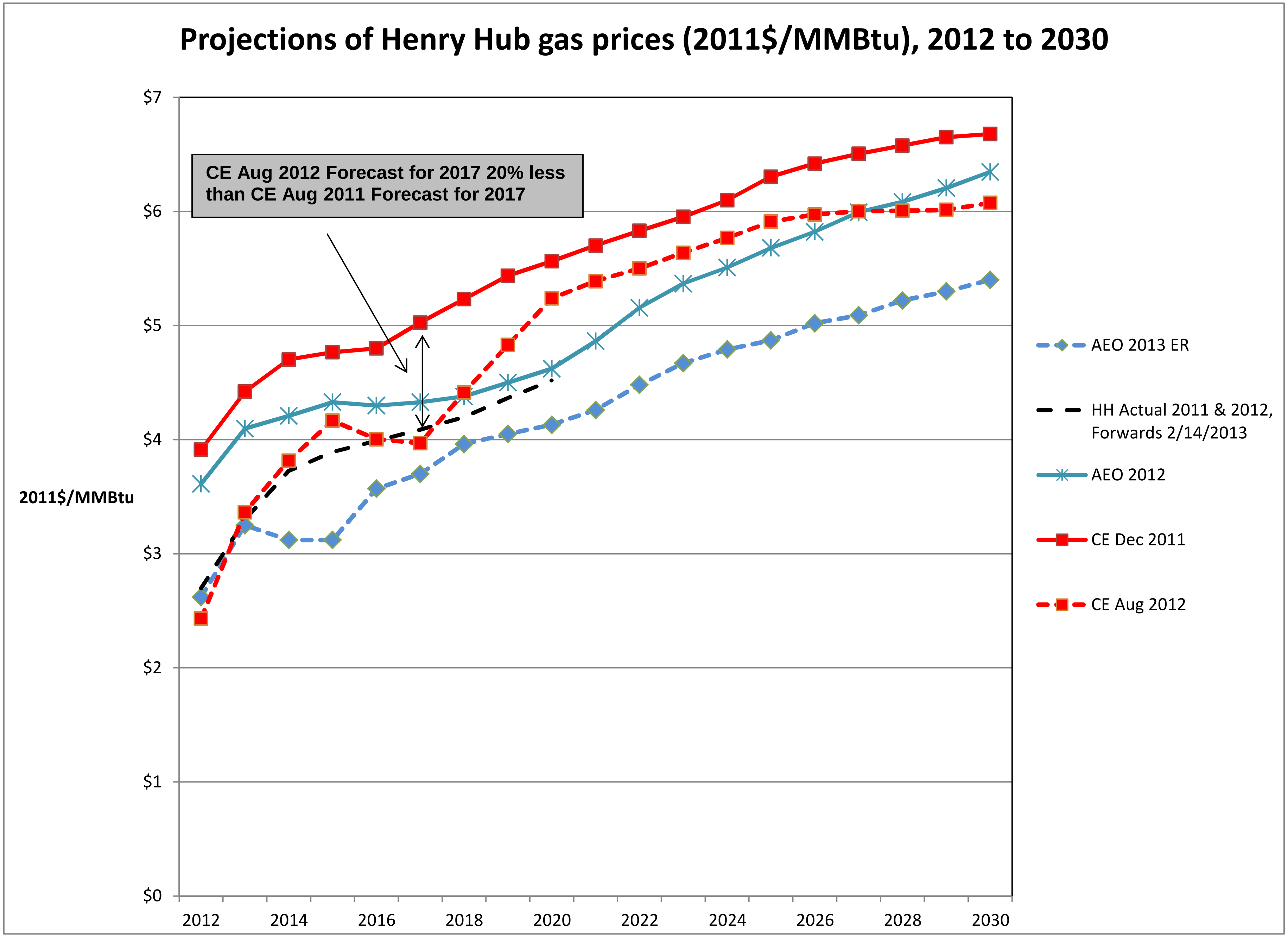
Natural Gas Supply, Disposition, and Prices, Reference case
(trillion cubic feet, unless otherwise noted)

Supply, Disposition, and Prices	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Production																		
Dry Gas Production 1/	20.580048	21.578024	22.953783	23.655727	22.762682	23.13645	23.653828	24.004753	24.229208	24.412531	24.775415	25.089409	25.399035	25.666735	25.917585	26.118557	26.278091	26.42881
Supplemental Natural Gas 2/	0.065156	0.067123	0.062	0.066	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446
Net Imports	**2.679003**	**2.577619**	**1.898744**	**1.637945**	**1.587339**	**1.74285**	**1.72809**	**1.367794**	**1.122282**	**0.985833**	**0.72441**	**0.348782**	**0.04679**	**-0.262536**	**-0.520131**	**-0.677069**	**-0.792785**	**-0.865837**
Pipeline 3/	2.260317	2.211392	1.648464	1.473675	1.451605	1.558594	1.563585	1.428544	1.383782	1.247333	1.18666	1.011782	0.70979	0.400464	0.142869	-0.014069	-0.129785	-0.202837
Liquefied Natural Gas	0.418686	0.366227	0.25028	0.164269	0.135735	0.184257	0.164505	-0.06075	-0.2615	-0.2615	-0.46225	-0.663	-0.663	-0.663	-0.663	-0.663	-0.663	-0.663
Total Supply	**23.324207**	**24.222767**	**24.914528**	**25.359673**	**24.414467**	**24.943745**	**25.446363**	**25.436993**	**25.415936**	**25.462809**	**25.564272**	**25.502636**	**25.510269**	**25.468643**	**25.461901**	**25.505934**	**25.549751**	**25.627419**
Consumption by Sector																		
Residential	4.779464	4.937562	4.910563	5.027832	4.857587	4.863903	4.851013	4.847425	4.844144	4.839925	4.834454	4.828053	4.815359	4.798106	4.783472	4.773751	4.764597	4.755865
Commercial	3.12078	3.202839	3.21164	3.312825	3.283586	3.310311	3.331202	3.353704	3.37744	3.400782	3.419922	3.429127	3.430935	3.426557	3.425405	3.433263	3.44486	3.456401
Industrial 4/	6.169769	6.599917	6.778983	6.811885	6.804032	6.969401	7.013375	7.044047	7.038836	7.063694	7.059746	7.080171	7.111031	7.174382	7.155704	7.141194	7.141239	7.117856
Natural Gas-to-Liquids Heat and Power 5/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas to Liquids Production 6/	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Power 7/	6.872128	7.377153	7.510502	7.857354	7.31612	7.655835	8.077168	7.988244	7.931267	7.933902	7.990174	7.874797	7.850177	7.75901	7.77954	7.835001	7.87044	7.963577
Transportation 8/	0.039051	0.03934	0.042502	0.045774	0.050816	0.055206	0.059692	0.064188	0.068667	0.073738	0.079089	0.084571	0.090321	0.096359	0.102262	0.108021	0.113736	0.119394
Pipeline Fuel	0.598218	0.632106	0.649474	0.687541	0.655402	0.659777	0.666759	0.663599	0.660665	0.658561	0.659896	0.659074	0.658729	0.658433	0.658088	0.658092	0.658831	0.659216
Lease and Plant Fuel 9/	1.275231	1.338347	1.412887	1.45497	1.380967	1.374829	1.392989	1.426659	1.446066	1.448863	1.480622	1.509297	1.5188	1.524182	1.5284	1.531043	1.533122	1.535218
Total	**22.854641**	**24.127266**	**24.51655**	**25.198181**	**24.348509**	**24.889263**	**25.3922**	**25.387867**	**25.367083**	**25.419468**	**25.523899**	**25.465088**	**25.475351**	**25.437027**	**25.432871**	**25.480366**	**25.526825**	**25.607527**
Discrepancy 10/	**0.469566**	**0.095501**	**0.397978**	**0.161491**	**0.065958**	**0.054482**	**0.054163**	**0.049126**	**0.048853**	**0.043341**	**0.040373**	**0.037548**	**0.034918**	**0.031616**	**0.02903**	**0.025568**	**0.022926**	**0.019892**
Natural Gas Prices																		
(2010 dollars per million Btu)																		
Henry Hub Spot Price	3.995644	4.39	3.937083	3.579107	4.063565	4.168796	4.290858	4.256473	4.292874	4.344403	4.463992	4.582374	4.824027	5.112452	5.321052	5.459375	5.633666	5.774337
Average Lower 48 Wellhead Price 11/	3.752976	4.062501	3.720474	3.322751	3.647279	3.73846	3.844126	3.81437	3.84587	3.890446	3.993827	4.096073	4.304509	4.552822	4.732111	4.850864	5.000352	5.120888
(2010 dollars per thousand cubic feet)																		
Average Lower 48 Wellhead Price 11/	3.8468	4.160001	3.809765	3.402498	3.734814	3.828183	3.936385	3.905915	3.938171	3.983817	4.089679	4.194379	4.407817	4.662089	4.845682	4.967286	5.120361	5.24379
Delivered Prices																		
Residential	12.250564	11.356326	10.646811	10.778775	10.694468	10.378978	10.564887	10.608962	10.674191	10.797894	10.943424	11.1092	11.421004	11.763456	12.006899	12.151587	12.328926	12.500584
Commercial	10.062461	9.322578	8.819593	8.898181	8.860094	8.668606	8.816828	8.820634	8.85316	8.944152	9.064072	9.208178	9.486646	9.794122	10.006846	10.12503	10.27459	10.414506
Industrial 4/	5.466698	5.649182	4.959185	4.517904	4.774044	4.865787	4.999366	4.975914	4.988129	5.037151	5.137411	5.252228	5.487089	5.754869	5.945259	6.054152	6.187409	6.311675
Electric Power 7/	4.974419	5.251998	4.767011	4.450637	4.521677	4.486081	4.648827	4.587286	4.57722	4.614848	4.714679	4.825366	5.03595	5.281925	5.465536	5.583711	5.72728	5.863953
Transportation 12/	14.521687	13.534248	12.835614	12.33827	12.532371	12.600795	12.712492	12.661082	12.635838	12.664173	12.738135	12.813912	13.028108	13.272305	13.431701	13.510259	13.61976	13.71186
Average 13/	**7.551241**	**7.333749**	**6.705836**	**6.505373**	**6.599125**	**6.481428**	**6.600142**	**6.589511**	**6.616117**	**6.683661**	**6.793507**	**6.931584**	**7.179845**	**7.463169**	**7.663484**	**7.780344**	**7.925908**	**8.060119**
(nominal dollars per million Btu)																		
Henry Hub Spot Price	3.95	4.39	4.02	3.702689	4.235213	4.413652	4.623559	4.668605	4.790421	4.933468	5.156782	5.385217	5.765045	6.215376	6.583309	6.875615	7.22848	7.555
Average Lower 48 Wellhead Price 11/	3.710104	4.062501	3.798828	3.437481	3.801343	3.95804	4.142189	4.183695	4.291609	4.417957	4.613649	4.813715	5.144185	5.535016	5.85466	6.109248	6.415884	6.700044
(nominal dollars per thousand cubic feet)																		
Average Lower 48 Wellhead Price 11/	3.802856	4.160001	3.890001	3.519981	3.892576	4.053033	4.241601	4.284104	4.394608	4.523989	4.724378	4.929244	5.267645	5.667856	5.995172	6.255871	6.569865	6.860846
Delivered Prices																		
Residential	12.11062	11.356326	10.871037	11.15095	11.146213	10.988592	11.384059	11.636172	11.911338	12.261998	12.64179	13.055558	13.648888	14.301223	14.855169	15.303885	15.819076	16.355455
Commercial	9.947514	9.322578	9.005339	9.205422	9.234352	9.17776	9.500461	9.67469	9.879249	10.156904	10.470771	10.821472	11.337194	11.907037	12.380665	12.751608	13.183185	13.626083
Industrial 4/	5.40425	5.649182	5.063627	4.673901	4.975703	5.151581	5.387002	5.457706	5.566257	5.720146	5.934712	6.172431	6.55745	6.996384	7.35559	7.624685	7.938979	8.25804
Electric Power 7/	4.917593	5.251998	4.867406	4.604311	4.712677	4.749574	5.009284	5.031449	5.107724	5.240583	5.446374	5.670783	6.018308	6.421411	6.762067	7.032206	7.348595	7.672251
Transportation 12/	14.355799	13.534248	13.105939	12.764293	13.061749	13.340908	13.698183	13.886989	14.100342	14.381329	14.715032	15.058941	15.569486	16.13558	16.617962	17.015015	17.475327	17.94026
Average 13/	7.46498	7.333749	6.847064	6.729994	6.877878	6.862118	7.111898	7.22754	7.382931	7.58991	7.847826	8.146014	8.580409	9.07322	9.481412	9.798678	10.169623	10.545661

1/ Marketed production (wet) minus extraction losses.
2/ Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
3/ Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
4/ Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
5/ Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
6/ Includes any natural gas converted into liquid fuel.
7/ Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
8/ Natural gas used as vehicle fuel.
9/ Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
10/ Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2009 and 2010 values include net storage injections.
11/ Represents lower 48 onshore and offshore supplies.
12/ Natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
13/ Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.
Sources: 2009 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 supply values; lease, plant, and pipeline fuel consumption; and wellhead price: EIA, Natural Gas Monthly, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). Other 2009 and 2010 consumption based on: EIA, Annual Energy Review 2010, DOE/EIA-0384(2010) (Washington, DC, October 2011). 2009 wellhead price: U.S. Department of the Interior, Office of Natural Resources Revenue; and EIA, Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2009 residential and commercial delivered prices: EIA, Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 residential and commercial delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130 (2011/07) (Washington, DC, July 2011). 2009 and 2010 electric power prices: EIA, Electric Power Monthly, DOE/EIA-0226, April 2010 and April 2011, Table 4.2, and EIA, State Energy Data System 2009, DOE/EIA-0214(2009) (Washington, DC, June 2011). 2009 and 2010 industrial delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey and industrial and wellhead prices from the Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the Natural Gas Monthly, DOE/EIA-0130(2011/07) (Washington, DC, July 2011). 2009 transportation sector delivered prices are based on: EIA, Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010) and estimated state taxes, federal taxes, and dispensing costs or charges. 2010 transportation sector delivered prices are model results.
Projections: EIA, AEO2012 National Energy Modeling System.

2027	2028	2029	2030	2031	2032	2033	2034	2035	Growth Rate (2010-2035)
26.544338	26.662075	26.79845	26.938108	27.038649	27.275412	27.461439	27.679752	27.925255	1.00%
0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	0.064446	-0.20%
-0.848708	**-0.837742**	**-0.859215**	**-0.894854**	**-0.91225**	**-0.973718**	**-1.083701**	**-1.199513**	**-1.360507**	**- -**
-0.201475	-0.199957	-0.221852	-0.273741	-0.29092	-0.336718	-0.4207	-0.536513	-0.697507	- -
-0.647233	-0.637784	-0.637363	-0.621113	-0.62133	-0.636999	-0.663	-0.663	-0.663	- -
25.760077	**25.888779**	**26.003681**	**26.1077**	**26.190844**	**26.36614**	**26.442184**	**26.544685**	**26.629194**	**0.40%**
4.746839	4.738064	4.728643	4.717326	4.703547	4.686532	4.673226	4.657225	4.641222	-0.20%
3.468729	3.484263	3.501068	3.51686	3.532466	3.54937	3.569906	3.584893	3.597954	0.50%
7.102633	7.086397	7.068275	7.03381	7.018875	7.037924	7.00787	7.005213	7.00455	0.20%
0	0	0	0	0	0	0	0	0	- -
0	0	0	0	0	0	0	0	0	- -
8.102383	8.234374	8.353859	8.470476	8.556707	8.685461	8.791811	8.883692	8.958923	0.80%
0.124803	0.129754	0.134584	0.140012	0.145219	0.150178	0.155156	0.15993	0.164503	5.90%
0.66024	0.660974	0.661932	0.662462	0.662653	0.665234	0.666559	0.668021	0.669316	0.20%
1.537466	1.540319	1.544087	1.554896	1.556297	1.572665	1.577227	1.588205	1.596532	0.70%
25.743092	**25.874146**	**25.992449**	**26.095842**	**26.175764**	**26.347364**	**26.441755**	**26.547178**	**26.632999**	**0.40%**
0.016985	**0.014633**	**0.011232**	**0.011858**	**0.015079**	**0.018776**	**0.000429**	**-0.002493**	**-0.003805**	**- -**
5.941228	6.032199	6.150507	6.289378	6.420352	6.581999	6.705719	7.055962	7.367666	2.10%
5.263762	5.341583	5.44273	5.561371	5.673185	5.811077	5.916536	6.21473	6.479685	1.90%
5.390092	5.469781	5.573356	5.694845	5.809342	5.950543	6.058533	6.363883	6.635198	1.90%
12.655519	12.775764	12.910732	13.07923	13.261782	13.466442	13.639338	14.001147	14.330761	0.90%
10.538301	10.626664	10.731106	10.863222	11.008595	11.173511	11.311042	11.637694	11.932157	1.00%
6.433536	6.511194	6.613722	6.730495	6.853752	7.001849	7.125254	7.443633	7.725685	1.30%
6.005096	6.094205	6.212243	6.345461	6.483529	6.638258	6.763607	7.091792	7.369217	1.40%
13.807224	13.859896	13.926097	14.02045	14.12267	14.244	14.343781	14.621464	14.868379	0.40%
8.184538	**8.266349**	**8.372382**	**8.500092**	**8.636939**	**8.787441**	**8.916483**	**9.239309**	**9.522986**	**1.10%**
7.9324	8.223775	8.566838	8.951182	9.351606	9.810854	10.189001	10.944579	11.665884	4.00%
7.027884	7.282249	7.580999	7.915067	8.263316	8.661749	8.989878	9.639735	10.259865	3.80%
7.196554	7.457023	7.762943	8.10503	8.461636	8.869631	9.205635	9.87109	10.506103	3.80%
16.89695	17.417362	17.982933	18.614651	19.316536	20.072517	20.724285	21.717333	22.691175	2.80%
14.070158	14.487468	14.947003	15.460779	16.034641	16.654768	17.186558	18.051355	18.89325	2.90%
8.589702	8.876795	9.212036	9.57899	9.982878	10.436665	10.826464	11.545901	12.232768	3.10%
8.017673	8.308308	8.652828	9.031	9.443627	9.894711	10.276958	11.000156	11.668339	3.20%
18.434643	18.895374	19.397202	19.954216	20.570469	21.231512	21.794649	22.679514	23.542433	2.20%
10.927543	11.26962	11.661614	12.097519	12.580192	13.098193	13.548145	14.331194	15.078596	2.90%


Projections of Henry Hub gas prices (2011$/MMBtu), 2012 to 2030
2011$/MMBtu
$7
$6
$5
$4
$3
$2
$1
$0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
AEO 2011
AEO 2012
CE Dec 2011


Projections of Henry Hub gas prices (2011$/MMBtu), 2012 to 2030
CE Aug 2012 Forecast for 2017 20% less than CE Aug 2011 Forecast for 2017
2011$/MMBtu
$7
$6
$5
$4
$3
$2
$1
$0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
AEO 2013 ER
HH Actual 2011 & 2012, Forwards 2/14/2013
AEO 2012
CE Dec 2011
CE Aug 2012

Natural Gas Price Forecasts

		Consumers Energy										Synapse			
		PCM Assumptions Book					Strategist Model								
	Year	Henry Hub Natural Gas	New Gen CT Delivered		New Gen CC Delivered		Gas - New NGCC		Gas - New NGCT		Henry Hub	New CT Delivered		New CC Delivered	
		nominal $/MMBtu	nominal $/MMBtu	% basis to Henry Hub	nominal $/MMBtu	% basis to Henry Hub	nominal $/MMBtu	% basis to Henry Hub	nominal $/MMBtu	% basis to Henry Hub	nominal $/MMBtu	nominal $/MMBtu	% basis to Henry	nominal $/MMBtu	% basis to Henry
Column / Line		a	b	c = b/a-1	d	e = d/a-1	f	g = f/a-1	h	i = h/a-1	j	k = j *(1+c)	l	m = j *(1+e)	n
1	2011 (2 mo)	3.73	4.49	20%	4.23	13%	$ 5.14	38%	$ 5.20	39%	$ 3.73	$ 4.49	20%	$ 4.23	13%
2	2012	3.99	4.72	18%	4.46	12%	$ 4.88	22%	$ 5.14	29%	$ 3.70	$ 4.38	18%	$ 4.14	12%
3	2013	4.6	5.34	16%	5.09	11%	$ 5.49	19%	$ 5.76	25%	$ 4.24	$ 4.92	16%	$ 4.69	11%
4	2014	4.99	5.74	15%	5.48	10%	$ 5.81	16%	$ 6.08	22%	$ 4.41	$ 5.08	15%	$ 4.85	10%
5	2015	5.16	5.92	15%	5.66	10%	$ 5.90	14%	$ 6.18	20%	$ 4.62	$ 5.30	15%	$ 5.07	10%
6	2016	5.3	6.07	15%	5.6	6%	$ 6.07	15%	$ 6.35	20%	$ 4.67	$ 5.35	15%	$ 4.93	6%
7	2017	5.66	6.44	14%	6.16	9%	$ 6.56	16%	$ 6.85	21%	$ 4.79	$ 5.45	14%	$ 5.21	9%
8	2018	6.01	6.81	13%	6.53	9%	$ 6.95	16%	$ 7.24	20%	$ 4.93	$ 5.59	13%	$ 5.36	9%
9	2019	6.37	7.18	13%	6.89	8%	$ 7.33	15%	$ 7.63	20%	$ 5.16	$ 5.81	13%	$ 5.58	8%
10	2020	6.65	7.47	12%	7.18	8%	$ 7.64	15%	$ 7.94	19%	$ 5.39	$ 6.05	12%	$ 5.81	8%
11	2021	6.95	7.78	12%	7.46	7%	$ 7.96	15%	$ 8.27	19%	$ 5.77	$ 6.45	12%	$ 6.19	7%
12	2022	7.25	8.09	12%	7.79	7%	$ 8.28	14%	$ 8.60	19%	$ 6.22	$ 6.94	12%	$ 6.68	7%
13	2023	7.55	8.4	11%	8.09	7%	$ 8.61	14%	$ 8.93	18%	$ 6.58	$ 7.32	11%	$ 7.05	7%
14	2024	7.89	8.76	11%	8.45	7%	$ 8.99	14%	$ 9.32	18%	$ 6.88	$ 7.63	11%	$ 7.36	7%
15	2025	8.32	9.2	11%	8.88	7%	$ 9.44	13%	$ 9.78	18%	$ 7.23	$ 7.99	11%	$ 7.72	7%
16	2026	8.64	9.53	10%	9.2	6%	$ 9.79	13%	$ 10.13	17%	$ 7.56	$ 8.33	10%	$ 8.04	6%
17	2027	8.93	9.84	10%	9.51	6%	$ 10.11	13%	$ 10.46	17%	$ 7.93	$ 8.74	10%	$ 8.45	6%
18	2028	9.21	10.14	10%	9.8	6%	$ 10.42	13%	$ 10.77	17%	$ 8.22	$ 9.05	10%	$ 8.75	6%
19	2029	9.5	10.44	10%	10.09	6%	$ 10.73	13%	$ 11.09	17%	$ 8.57	$ 9.41	10%	$ 9.10	6%
20	2030	9.73	10.68	10%	10.32	6%	$ 10.98	13%	$ 11.35	17%	$ 8.95	$ 9.83	10%	$ 9.49	6%
21	2031	10.09	11.06	10%	10.69	6%	$ 11.38	13%	$ 11.75	16%	$ 9.35	$ 10.25	10%	$ 9.91	6%
22	2032	10.46	11.44	9%	11.07	6%	$ 11.78	13%	$ 12.16	16%	$ 9.81	$ 10.73	9%	$ 10.38	6%
23	2033	10.87	11.87	9%	11.49	6%	$ 12.22	12%	$ 12.61	16%	$ 10.19	$ 11.13	9%	$ 10.77	6%
24	2034	11.28	12.29	9%	11.91	6%	$ 12.67	12%	$ 13.06	16%	$ 10.94	$ 11.92	9%	$ 11.56	6%
25	2035	11.64	12.67	9%	12.28	5%	$ 13.06	12%	$ 13.47	16%	$ 11.67	$ 12.70	9%	$ 12.31	5%
26	2036	12.05	13.09	9%	12.69	5%	$ 13.50	12%	$ 13.91	15%	$ 12.30	$ 13.34	8%	$ 12.94	5%
27	2037	12.44	13.5	9%	13.09	5%	$ 13.93	12%	$ 14.35	15%	$ 12.97	$ 14.03	8%	$ 13.62	5%
28	2038	12.83	13.91	8%	13.5	5%	$ 14.36	12%	$ 14.78	15%	$ 13.68	$ 14.76	8%	$ 14.35	5%
29	2039	13.23	14.32	8%	13.9	5%	$ 14.78	12%	$ 15.21	15%	$ 14.42	$ 15.51	8%	$ 15.09	5%
30	2040	13.62	14.73	8%	14.3	5%	$ 15.21	12%	$ 15.65	15%	$ 15.20	$ 16.31	7%	$ 15.88	4%
Average 2012-2030				**11%**		**7%**		**14%**		**18%**			**11%**		**7%**

Notes

a, b, d	MEC-CE-78, Attachment 1, page 134 of 161
f, h	Consumers Energy Strategist Model Inputs
c, e, g, i	Synapse calculations
j	AEO 2012 nominal HH prices, available at: http://www.eia.gov/oiaf/aeo/tablebrowser/
k,l,m,n	Synapse calculations

Synapse
Energy Economics, Inc.

2012 Carbon Dioxide Price Forecast

October 4, 2012

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Table of Contents

1. Executive Summary

Electric utilities and others should use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. Estimating this price can be difficult because, despite several attempts, the federal government has not come to consensus on a policy (or a set of policies) to reduce greenhouse gas (GHG) emissions in the U.S.

Although this lack of a defined policy certainly creates challenges, a “zero” price for the long-run cost of carbon emissions is not a reasonable estimate. The need for a comprehensive effort in the U.S. to reduce GHG emissions has become increasingly clear, and it is certain that any policy requiring, or leading to, these reductions will result in a cost associated with emitting CO_2 over some portion of the life of long-lived electricity resources. Prudent planning requires a reasonable effort to forecast CO_2 prices despite the considerable uncertainty with regard to specific regulatory details.

This 2012 forecast seeks to define a reasonable range of CO_2 price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. This forecast updates Synapse’s 2011 CO_2 price forecast, which was published in February of 2011. Our 2012 forecast incorporates new data that has become available since 2011, and extends the study period end-date to 2040 in order to provide recommended CO_2 price estimates for utilities planning 30 years out into the future.

A. Key assumptions

Synapse’s 2012 CO_2 price forecast reflects our expectation that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in or around 2020. These assumptions are based on the following reasoning:

- We believe that a federal cap-and-trade program for GHGs is a key component of the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost.
- We believe that federal legislation is likely by the end of the session in 2017 (with implementation by about 2020) prompted by one or more of the following factors:
    - technological opportunity
    - a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
    - a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
    - increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions that are driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

In addition to the assumptions regarding a federal GHG program described above, we anticipate that regional and state policies will lead to costs associated with GHGs in the near-term (i.e., prior to 2020). Prudent planning requires that utilities take these costs into account when engaging in resource planning.

B. Study approach

To develop its 2012 CO_2 price forecast, Synapse reviewed more than 40 carbon price estimates and related analyses, including:

- McKinsey & Company's 2010 analyses of the marginal abatement costs and abatement potential of GHG mitigation technologies
- Analyses of the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years, including analyses by the Energy Information Association (EIA) and the Environmental Protection Agency (EPA)
- The U.S. Interagency Working Group's estimates for the social cost of carbon
- Analyses of the factors that affect projections of allowance prices, including analyses by the EIA and Resources for the Future
- CO_2 price estimates used by utilities in a wide range of publicly available utility Integrated Resource Plans

Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of the various Congressional proposals to date using this approach offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

Synapse also considered the impact on CO_2 prices of regulatory measures outside of a cap-and-trade program—such as a federal Renewable Portfolio Standard—that could simultaneously help to achieve the emission-reduction goals of cap-and-trade. These "complementary policies" result in lower CO_2 allowance prices, since they would reduce the demand for CO_2 emissions allowances under cap-and-trade.

C. Synapse's 2012 CO_2 price forecast

Based on analyses of the sources described above, and relying on its own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. These cases represent different appetites for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040.[1] This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario).
- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets (nationally or internationally); restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; or higher baseline emissions.

Table ES-1 presents Synapse's Low, Mid, and High case price projections for each year of the study period, as well as the levelized cost for each case.

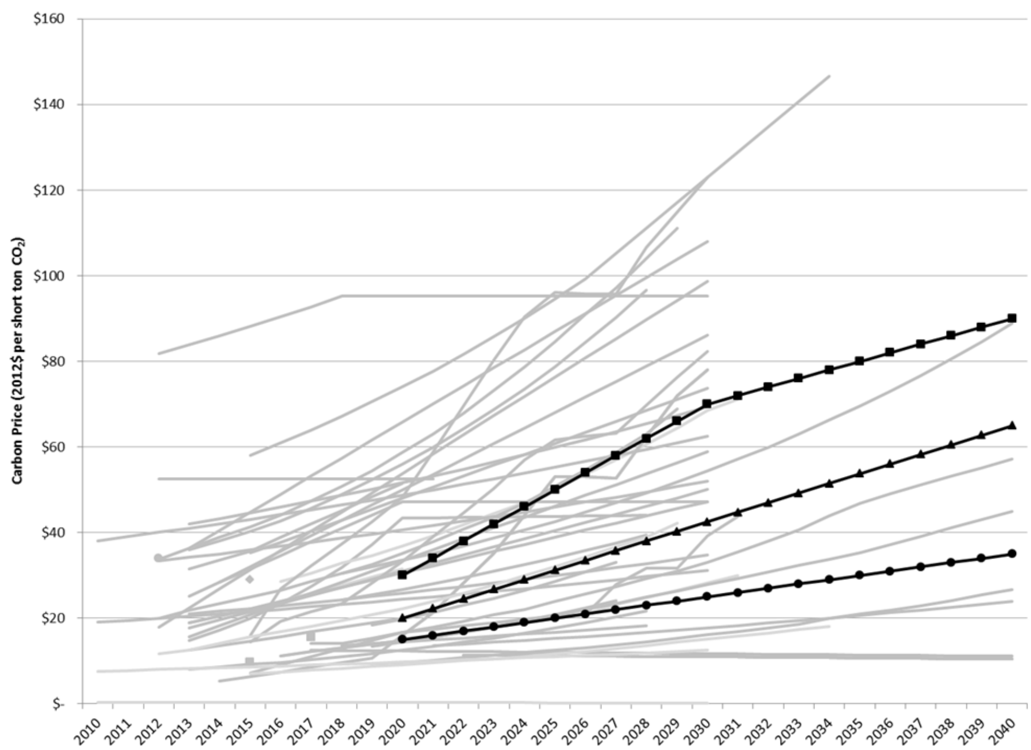
Figure ES-1 presents Synapse's Low, Mid, and High case forecasts as compared to a broad range of CO_2 allowance prices used by utilities in resource planning over the past three years. Synapse forecasts are represented by black lines, while utility forecasts are represented by grey.

[1] Throughout this report, CO_2 allowance prices are presented in $2012 per short ton CO_2, except in reference to a few original sources, where alternate units are clearly labeled. Results from other modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis. Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Results originally provided in metric tonnes were converted to short tons by multiplying by a factor of 1.1.

Table ES-1: Synapse 2012 CO_2 allowance price projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

Figure ES-1: Synapse forecasts compared to a range of utility forecasts



2. Structure of this Paper

This paper presents Synapse's assumptions, data sources, and estimates of reasonable future CO_2 prices for use in resource planning analyses. The report is structured as follows:

- Section 3 discusses the key assumptions behind Synapse's estimates
- Sections 4 through 8 present data from the sources reviewed by Synapse in developing its estimates of the future price of CO_2 emissions
- Section 9 presents Synapse's 2012 Low, Mid, and High CO_2 price forecasts, and compares these projections to a range of utility forecasts
- Appendix A provides a more detailed discussion of state and regional GHG initiatives. Collectively, these initiatives suggest that momentum is building toward federal GHG action

3. Discussion of Key Assumptions

A. Federal GHG legislation is increasingly likely

Congressional action in the form of cap-and-trade or clean energy standards is only one avenue in an increasingly dynamic and complex web of activities that could result in internalizing a portion of the costs associated with emissions of greenhouse gases from the electric sector. The states, the federal courts, and federal agencies are also grappling with the complex issues associated with climate change. Many of these efforts are proceeding simultaneously.

Nonetheless, we believe that a federal cap-and-trade program for GHGs is the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost. Several cap-and-trade proposals have been taken up by Congress in the past few years, though none yet have been passed by both houses. (More discussion of this topic is provided in Section 5 of this report.)

We further believe that federal action will occur in the near-term. This 2012 CO_2 price forecast assumes that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in 2020, prompted by one or more of the following factors:

- technological opportunity
- a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
- a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
- increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

B. State and regional initiatives building toward federal action

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to wait for federal action, are already pursuing policies on their own or in regional groups. These policies are described below, and are discussed in more detail in Appendix A of this report.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [2]

Under the Regional Greenhouse Gas Initiative (RGGI), ten Northeast and Mid-Atlantic states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.

Meanwhile, California's Global Warming Solutions Act (AB 32) has created the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS). The first compliance period for California's cap-and-trade program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e[3] per year. The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[4] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state-level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[5] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[6]

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[2] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

[3] CO2e refers to carbon dioxide equivalent, a measure that includes both carbon dioxide and other greenhouse gases converted to an equivalent amount of carbon dioxide based on their global warming potential.

[4] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

[5] Minnesota Statutes 2008 § 216B.241

[6] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

Currently, 29 U.S. states have renewable portfolio standards. Eight others have renewable portfolio goals. In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories, greenhouse gas registries, climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI (requiring specific emissions reductions from power plants in the state), and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

4. Marginal Abatement Costs and Technologies

This chapter presents key data related to marginal abatement costs for CO_2, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions.

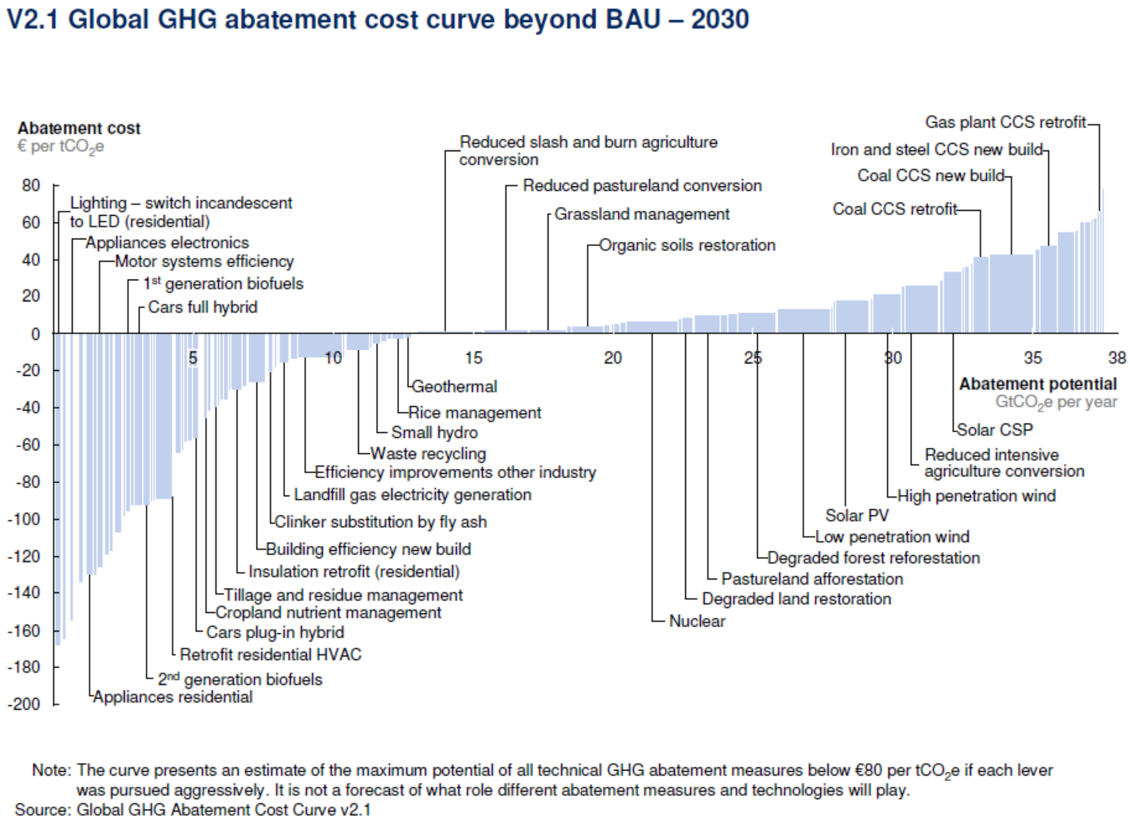
The long-run marginal abatement cost for CO_2 represents the cost of the control technologies necessary for the last (or most expensive) unit of emissions reduction required to comply with regulations. This cost depends on emission reduction goals: lower emissions reduction targets can be met by lower-cost technologies, while more stringent targets will require additional reduction technologies that are implemented at higher costs. The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2° Celsius. Atmospheric concentrations of CO_2 would need to be stabilized at 450 ppm in order to limit the global temperature increase to no more than 2°C.[7]

In recent years, there have been several analyses of technologies that would contribute to emission reductions consistent with an increase in temperature of no more than 2°C. McKinsey & Company examined these technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are shown in Figure 1. Global mitigation options are ordered from least expensive to most expensive, and the width of each bar represents the amount of mitigation likely at these costs. The chart represents a marginal abatement cost price curve, where cost of abatement is shown on the y-axis and cumulative metric tonnes of GHG reductions are shown on the x-axis. It is likely that the lowest cost reductions will be implemented first, but as reduction targets become more stringent and low-cost options are saturated, the cost of the marginal abatement technology is likely to increase.

The chart below, from the McKinsey report, provides a useful reference to the types of options and technologies that might be employed at specific CO_2 prices.

[7] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Figure 1: McKinsey & Company marginal abatement technologies and associated costs for the year 2030[8]



As shown in Figure 1, technologies for carbon mitigation that are available to the electric sector include those related to energy efficiency, nuclear power, renewable energy, and carbon capture and storage (CCS) for fossil-fired generating resources. McKinsey estimates CCS technologies to cost 50-60 €/metric tonne (2005€). Converted into current dollars, this is equivalent to $65 to $85/ton ($71.5 to $93.5/metric tonne, 2012$). According to the International Energy Agency (IEA), "in order to reach the goal of stabilizing global emissions at 450 ppm by 2050, CCS will be necessary."[9] If this is true, it is reasonable to expect that a CO_2 allowance price will rise to $65/ton or higher under a GHG policy designed to limit the global temperature increase to no more than 2°C. However, if significant reductions could be accomplished with CCS at the high $65 to $85/ton CO_2 range, we would not expect CO_2 mitigation prices to significantly exceed the top of that range.

[8] McKinsey & Company. *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.* 2010. Page 8.
[9] International Energy Agency. *Technology Roadmap: Carbon Capture and Storage*. 2009. Page 4.

5. Analyses of Major Climate Change Bills

This chapter presents key data related to analyses of major climate change bills proposed in Congress over the past few years, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions. Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of these proposals offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

A. Cap-and-trade proposals

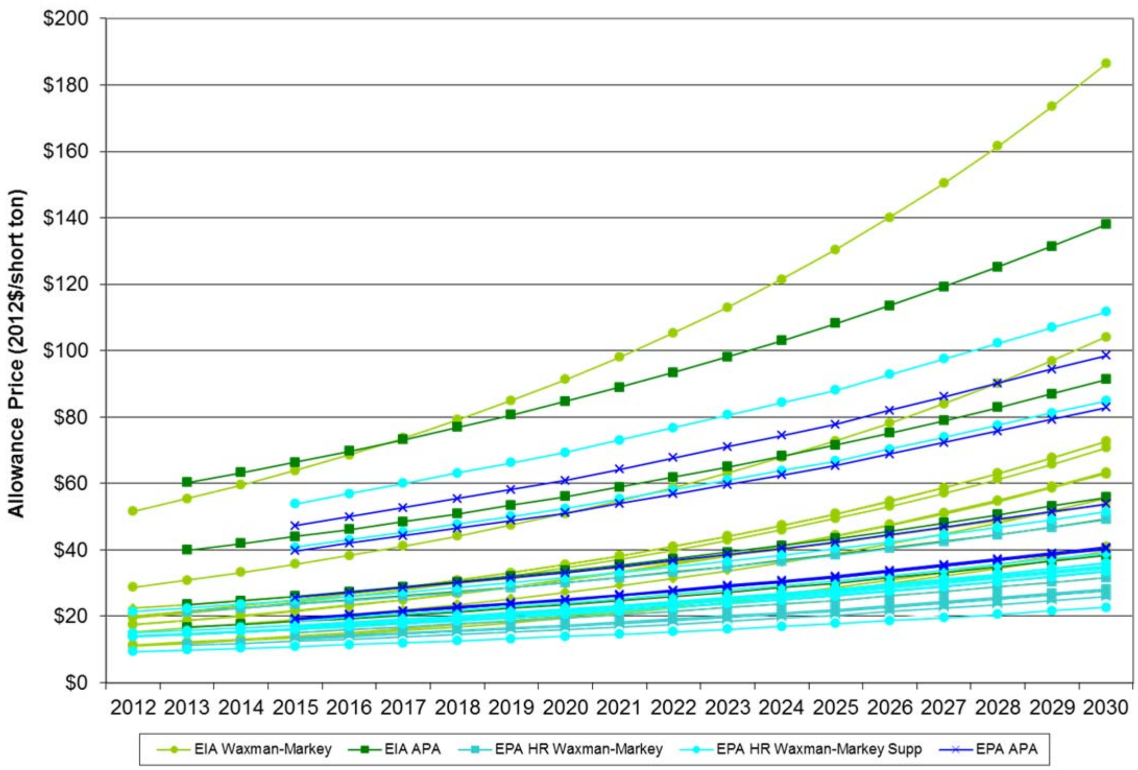
In the past decade, the expectation has been that action on climate change policy will occur at the Congressional level. Legislative proposals have largely taken the form of cap-and-trade programs, which would reduce greenhouse gas emissions through a federal cap, and would allow trading of allowances to promote reductions in GHG emissions where they are most economic. Legislative proposals and President Obama's stated target aim to reduce emissions by up to 80% from current levels by 2050.

Comprehensive climate legislation was passed in the House in the 111th Congress in the form of the American Clean Energy and Security Act of 2009 (ACES, also known as Waxman-Markey and HR 2454); however, the Senate ultimately did not take up climate legislation in that session. HR 2454 was a cap-and-trade program that would have required a 17% reduction in emissions from 2005 levels by 2020, and an 83% reduction by 2050. It was approved by the House of Representatives in June, 2009, but the Senate bill, known as the American Power Act of 2010 (APA, also known as Kerry-Lieberman), never came to a vote.

Figure 2 shows the results of EIA and EPA analyses of HR 2454 and APA. The chart shows the forecasted allowance prices in the central scenarios, as well as a range of sensitivities. Figure 3 shows these values as levelized prices for the time period 2015 to 2030.[10]

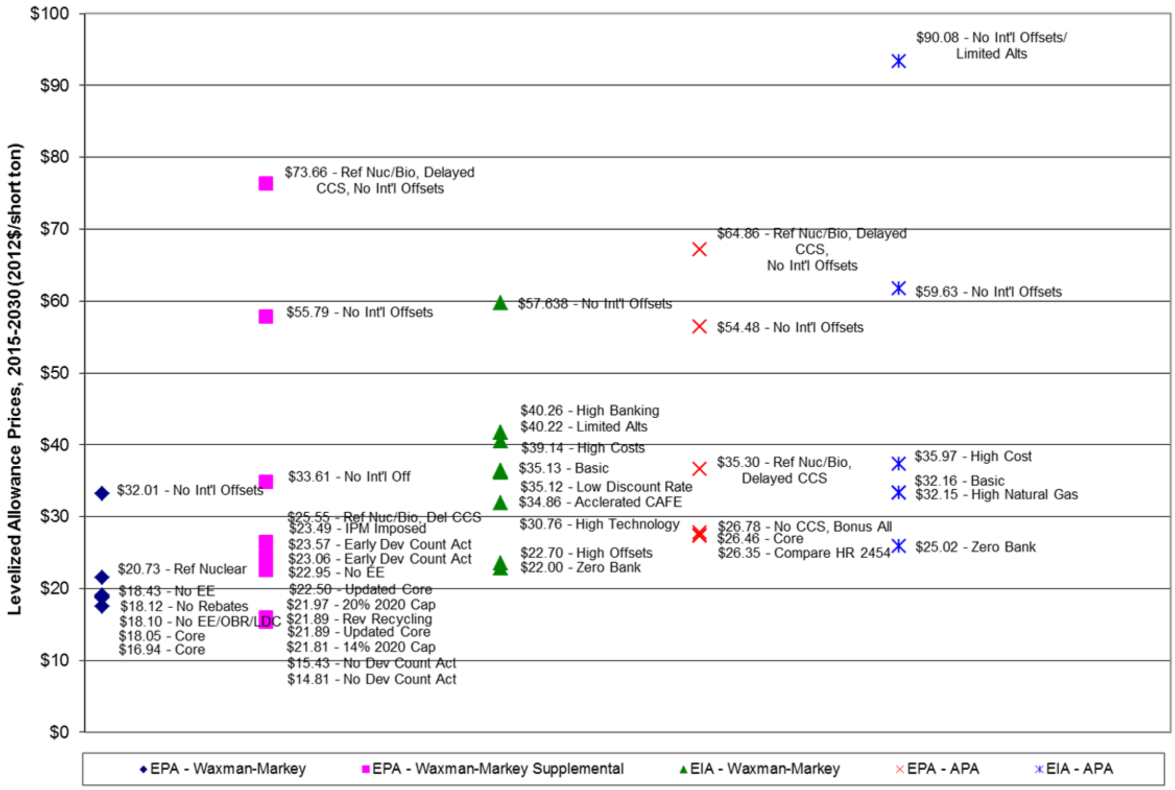
[10] Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

Figure 2: Greenhouse gas allowance price projections for HR 2454 and APA 2010[11]



[11] Sources for Figure 2 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html
U.S. Environmental Protection Agency ("EPA"); *Analysis of the American Power Act of 2010 in the 111th Congress* (June 2010). Available at http://www.epa.gov/climatechange/Downloads/EPAactivities/EPA_APA_Analysis_6-14-10.pdf
EPA; *Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (January 2010). Available at: Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf
EPA; *Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (June 2009). Available at: http://www.epa.gov/climatechange/Downloads/EPAactivities/HR2454_Analysis.pdf

Figure 3: GHG allowance price projections for HR 2454 and APA 2010 - levelized 2015-2030



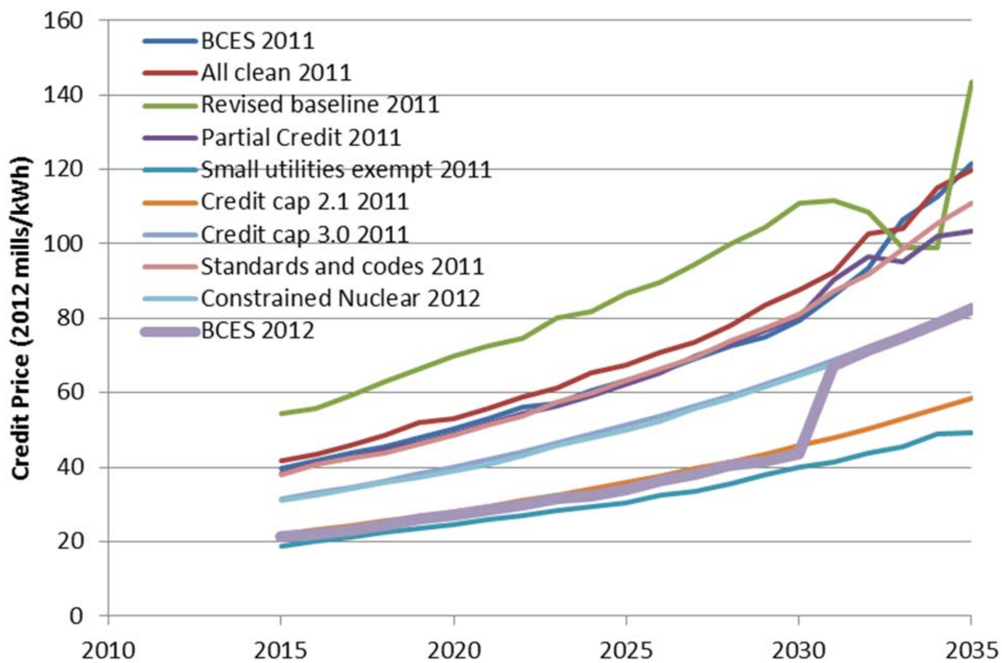
B. Clean Energy Standard

The 112th Congress chose not to revisit legislation establishing an economy-wide emissions cap, and instead focused on policies aimed at fostering technology innovation and developing renewable energy or clean energy standards. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S.2146), under which larger utilities would be required to meet a percentage of their sales with electric generation from sources that produce fewer greenhouse gas emissions than a conventional coal-fired power plant. All generation from wind, solar, geothermal, biomass, municipal solid waste, and landfill gas would earn a full CES credit, as would hydroelectric and nuclear facilities. Lower-carbon fossil facilities, such as natural gas and coal with carbon capture, would earn partial credits based on their CO_2 emissions. Generation owners would be required to hold credits equivalent to 24% of their sales beginning in 2015, and the CES requirement rises over time to 84% by 2035, creating demand for renewable energy and low-emissions technologies. The credits generated by these clean technologies would be tradable and have a value that would change depending on how costly the policy is to achieve. The Clean Energy Standard would apply to utilities with sales greater than 2 million MWh, and expand to include those with sales greater than 1 million MWh by 2025.

The EIA conducted analyses of a potential Clean Energy Standard in both 2011 and 2012.[12,13] All of these cases result in some level of increase in nuclear, gas, and renewable generation, typically at the expense of coal. The exact generation mix, as well as the resulting reduction in emissions, is highly dependent on both the technology costs and policy design. The resulting CES credit prices (Figure 4) vary widely, from 25 to 70 mills/kWh in 2020,[14] rising to 47 to 138 mills/kWh in 2035. The credit cap cases show a smaller rise in credit prices. When credit prices are capped at a specific value, clean energy deployment and emissions abatement is reduced.

An effective CO_2 allowance price can be calculated based on the fact that this policy gives existing gas combined cycle units 0.48 credits and existing coal units zero credits, and the emissions from an average gas unit are about 0.57 tCO_2/MWh and from an average coal unit 1.125 tCO_2/MWh.[15] For the BCES 2012 case, for example, this conversion would result in effective allowance prices of \$18.4/tCO_2 in 2015 and \$71.4/tCO_2 in 2035.

Figure 4: CES credit prices in EIA analyses of a U.S. Clean Energy Standard



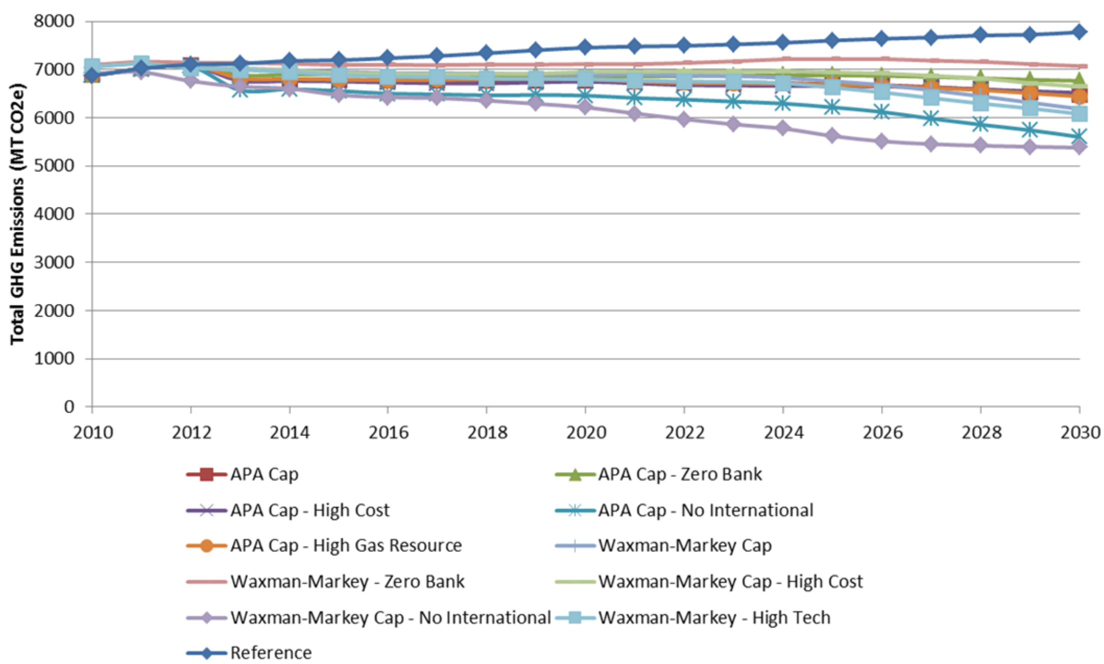
12 US EIA. 2011. Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman. http://www.eia.gov/analysis/requests/ces_bingaman/.
13 US EIA. 2012. Analysis of the Clean Energy Standard Act of 2012. http://www.eia.gov/analysis/requests/bces12/.
14 A mill is one one-hundredth of a cent. Therefore, these CES prices in 2020 represent costs of 0.25 to 0.70 ¢/kWh, or \$2.5 to \$7/MWh.
15 EPA Air Emissions Overview, Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.htm

6. Key Factors Affecting Allowance Price Projections

Dozens of analyses over the past several years have shown that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these factors derive from the details of policy design, while others pertain to the context in which a policy would be implemented.

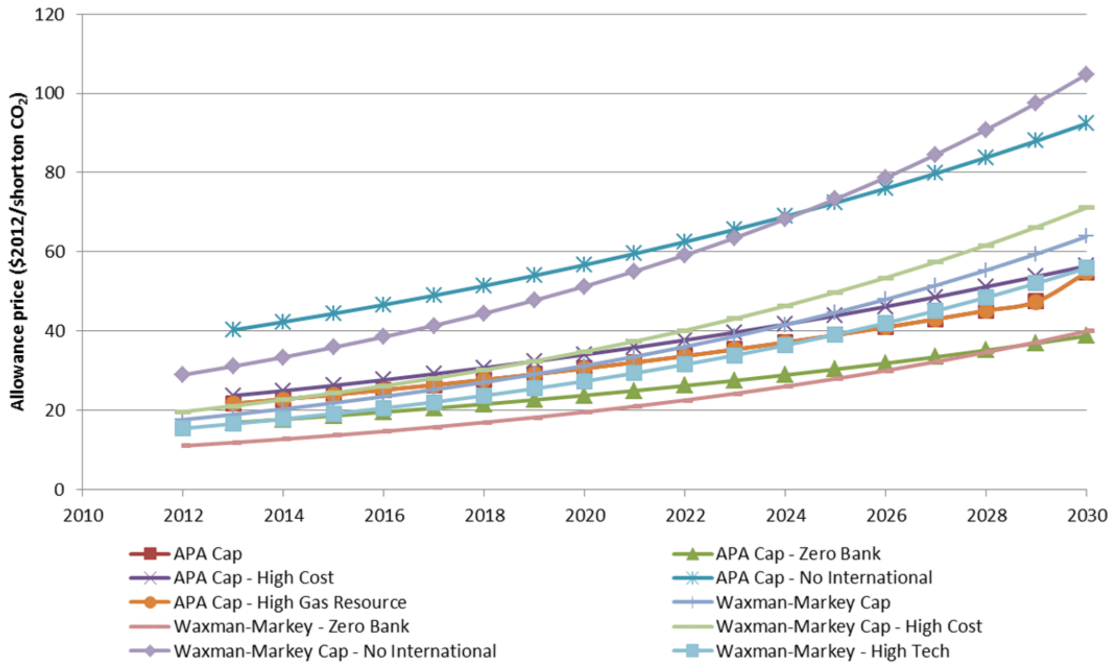
Factors in a forecast include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps including international offsets) and allowance banking; assumptions about technological progress; the presence or absence of a “safety valve” price; and treatment of emissions co-benefits. Figures 5 and 6 show the very significant ranges in emissions and allowance prices for the Waxman-Markey and APA federal cap-and-trade policies, as well as several associated sensitivities, including assumptions on banking, international offsets, technology cost and progress, and gas supply.

Figure 5: GHG Emissions in Waxman-Markey and APA policies and sensitivities[16]



[16] Sources for Figure 5 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

Figure 6: Allowance prices in ACES and APA policies and sensitivities[17]



A. Assessing the potential impact of a natural gas supply increase

The recent shale gas boom has put substantial downward pressure on natural gas prices. Several factors could influence future gas prices, including the estimated ultimate recovery per well and regulations addressing the environmental impacts of hydraulic fracturing.[18] The impact of higher or lower gas prices on carbon prices is uncertain. In the near term, lower natural gas prices are likely to make emissions mitigation in the electric sector less expensive, as gas power plants can displace coal plants at lower cost. Conversely, as marginal electricity prices are frequently set by natural gas plants, lower gas prices will contribute to lower electricity prices, potentially increasing electricity consumption and associated emissions. Lower electricity prices also make it more difficult for renewable technologies with even lower emissions than gas to compete in electricity markets.

In 2010, Resources for the Future (RFF) used a version of the EIA's National Energy Modeling System (NEMS) energy model to test effects of increased gas supply from shale gas on the economics of energy policy. Under a moderate climate policy, the high gas scenario decreased the 2030 allowance price by less than 1%, from $61.1 to $60.8 per ton of CO_2.[19] The EIA showed

[17] Sources for Figure 6 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html
[18] EIA (2012) "Projected natural gas prices depend on shale gas resource economics" http://www.eia.gov/todayinenergy/detail.cfm?id=7710
[19] Brown et al (2010). "Abundant Shale Gas Resources: Some Implications for Energy Policy". Available at: http://www.rff.org/RFF/Documents/RFF-BCK-Brownetal-ShaleGas.pdf

similar results in its analysis of the American Power Act: increased gas supply decreased the 2030 allowance price by less than 0.1%, from $49.80 to $49.78 per ton of CO_2.[20] In the policies studied by EIA and RFF, the result of an increased gas supply amounted to an inconsequential reduction in CO_2 prices. At this point it appears that, while a large shale gas resource may change how each policy is met, it is not a significant factor in the CO_2 cost that utilities should use for planning. Ongoing studies are expected to provide further insight into this issue.[21]

[20] EIA (2010) “Energy Market and Economic Impacts of the American Power Act of 2010”. Available at: http://www.eia.gov/oiaf/servicerpt/kgl/index.html

[21] The Energy Modeling Forum will evaluate carbon constraints under cases of reference and high case supply levels in the EMF 26 study, which began in late 2011 and is ongoing (see http://emf.stanford.edu/research/emf_26/)

7. The U.S. Interagency Social Cost of Carbon

In 2010, the U.S. government began to use “social cost of carbon” values in an attempt to account for the damages resulting from climate change.[22] Four values for the social cost of carbon were initially provided by the Interagency Working Group on the Social Cost of Carbon, a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others. This group was tasked with the development of a consistent value for the global societal benefits of climate change abatement. These values, \$5, \$21, \$35, and \$65 per metric tonne of CO_2 in 2007 dollars (\$4.9, \$20.7, \$34.5, and \$64.0 per ton in 2012 dollars), reflected three discount rates and one estimate of the high cost tail-end of the distribution of impacts. As of May 2012, these estimates have been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[23]

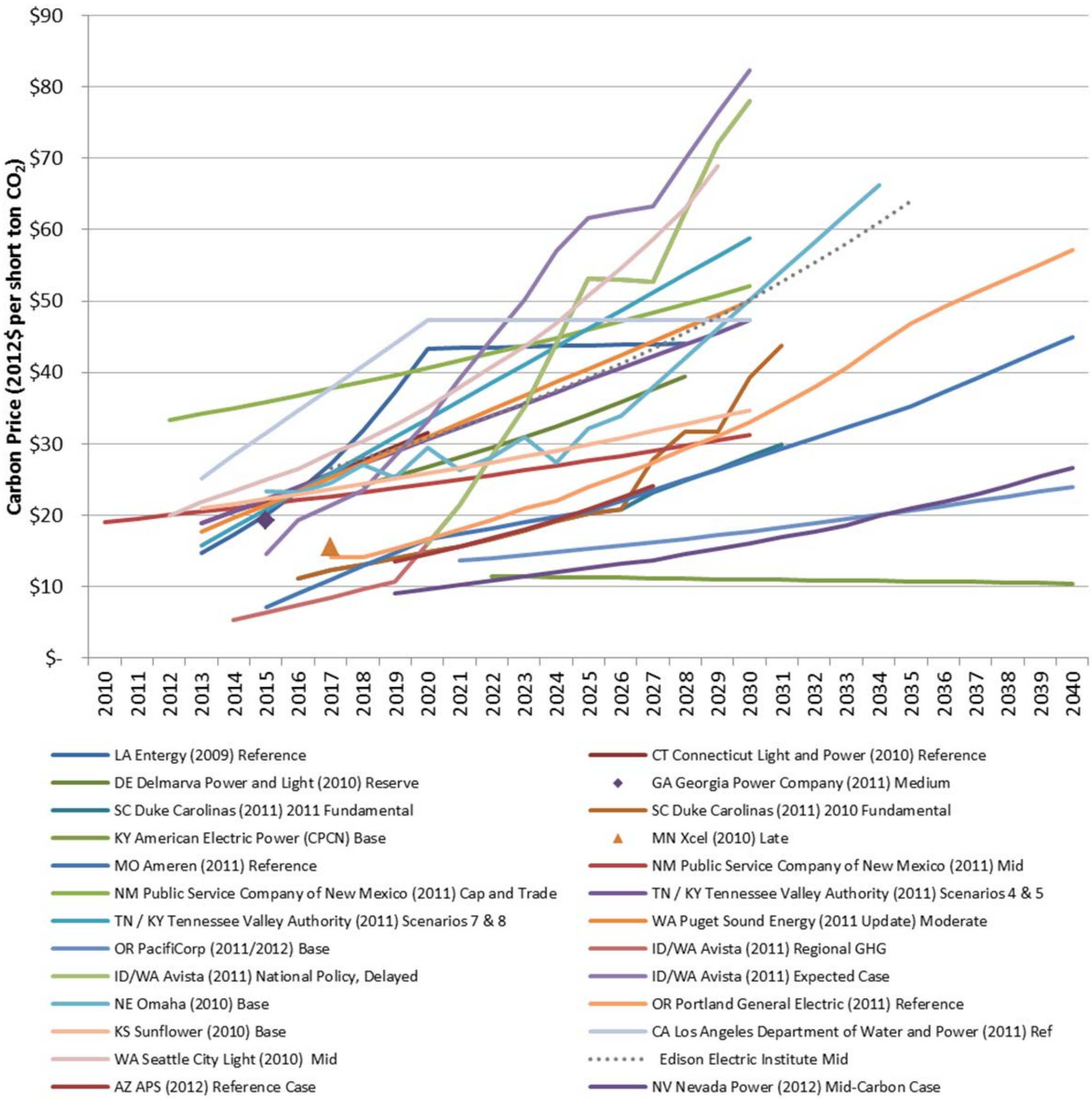
The U.S. “social cost” values are the result of analysis using the DICE, PAGE, and FUND integrated assessment models. The combination of complex climate and economic systems with these reduced-form integrated assessment models leads to substantial uncertainties. In a 2012 paper, Ackerman and Stanton[24] explored the impact of specific assumptions used by the Interagency Working Group, and found values for the social cost of carbon ranging from the Working Group’s level up to more than an order of magnitude greater. Despite limitations in the calculations for the social cost of carbon stemming from the choice of socio-economic scenarios, modeling of the physical climate system, and quantifying damages around the globe for hundreds of years into the future, this multi-agency effort represents an important initial attempt at incorporating consistent values for the benefits associated with CO_2 abatement in federal policy.

[22] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.
[23] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government’s Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15
[24] Frank Ackerman and Elizabeth A. Stanton (2012). Climate Risks and Carbon Prices: Revising the Social Cost of Carbon. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10

8. CO_2 Price Forecasts in Utility IRPs

A number of electric companies have included projections of costs associated with greenhouse gas emissions in their resource planning procedures. Figure 7 presents the mid-case values of publicly available forecasts used by utilities in resource planning over the past three years.

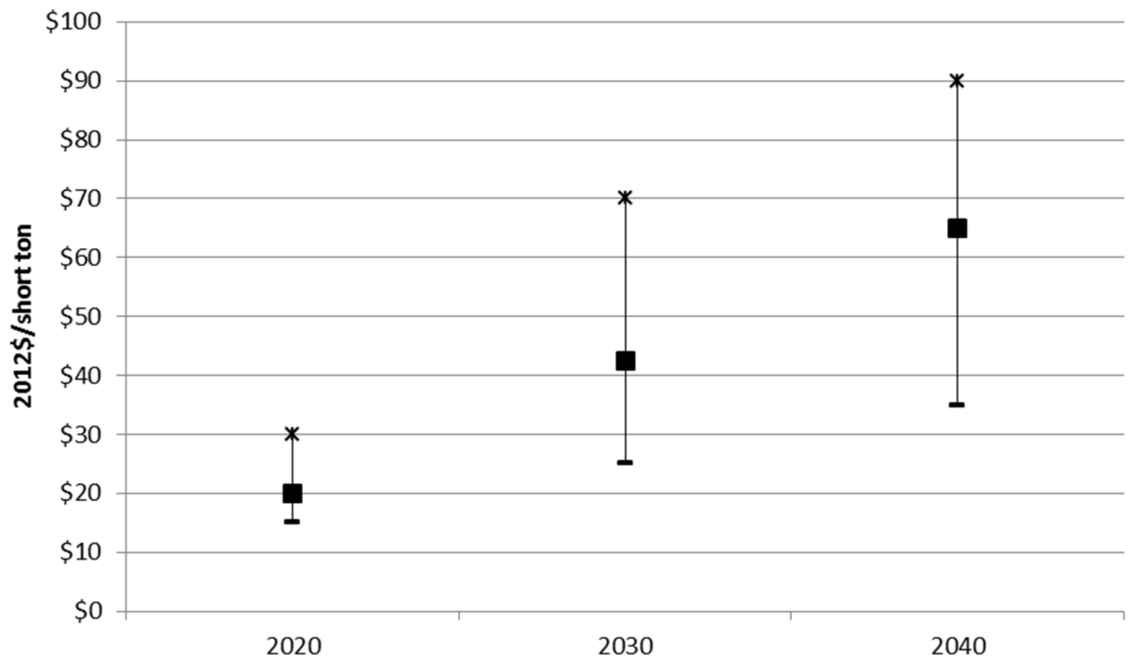
Figure 7: Utility Mid Case CO_2 Price Forecasts



9. Recommended 2012 CO_2 Price Forecast

Based on analyses of the sources described in Sections 4 through 8, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. Figure 8 shows the range covered by the Synapse forecasts in three years: 2020, 2030, and 2040. These forecasts share the common assumption that a federal cap-and-trade policy will be passed sometime within the next five years, and will go into effect in 2020. All annual allowance prices and levelized values are reported in 2012 dollars per ton of carbon dioxide.[25]

Figure 8: Synapse 2012 Forecast Values



Each of the forecasts shown in Figure 8 represents a different appetite for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040, representing a $23/ton levelized price over the period 2020-2040. This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario). Such complementary policies would

[25] All values in the Synapse Forecast are presented in 2012 dollars. Results from EIA and EPA modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade, and would thus lower the expected allowance prices associated with the achievement of any particular federally mandated goal.

- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040, representing a $39/ton levelized price over the period 2020-2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. These complementary policies would include renewables, energy efficiency, and transportation standards, as well as some level of allowance banking and offsets. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040, representing a $59/ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

Synapse's Low, Mid, and High case price projections for each year of the study period are presented in graphic and tabular form, below.

Figure 9: Synapse 2012 CO_2 Price Trajectories

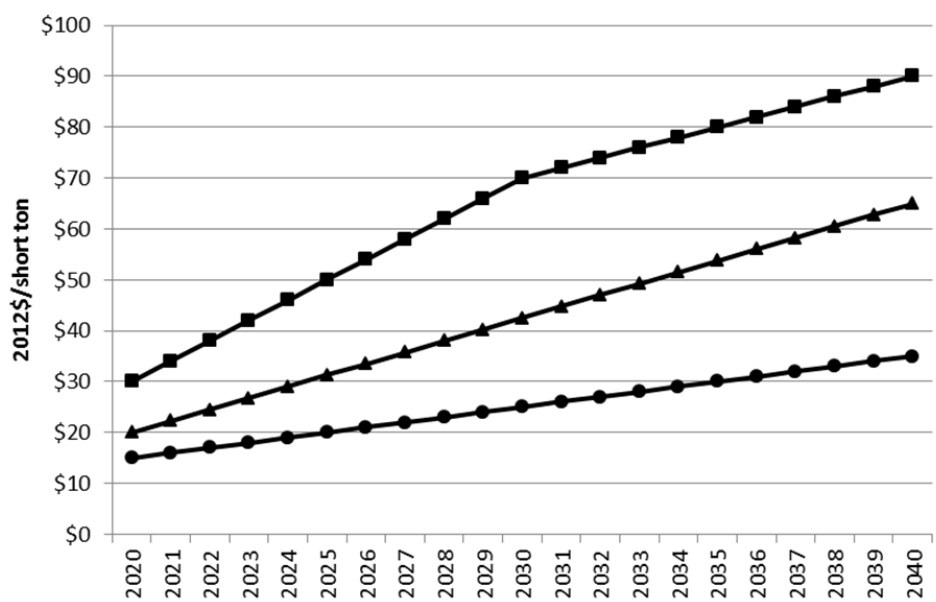


Table 1: Synapse 2012 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

The following charts compare the Synapse Mid, High, and Low case forecasts against various utility estimates. Data on utility estimates was collected from a wide range of available public Integrated Resource Plans (IRPs). We have excluded several IRPs with zero carbon prices or IRPs with no carbon price given, accounting for 9 of 65 collected.

Figure 10 shows 26 utility CO_2 price forecasts, with 2030 prices ranging from $10/t$CO_2$ to above $80/t$CO_2$. Due to the extended development period of many IRPs, some of these forecasts may not accurately reflect very recent years; a NM Public Service forecast, for example, begins in 2010, when there was no economy-wide CO_2 price. Nevertheless, IRPs do their best to represent accurate views of the future, in order to develop least-cost plans. The Synapse Mid forecast, beginning at $20/t$CO_2$ and rising to $65/t$CO_2$, lies well within the range of the mid-case forecasts shown here.

Figure 10: Synapse 2012 Mid forecast as compared to the Mid forecasts of various U.S. utilities (2010-2012)[26]

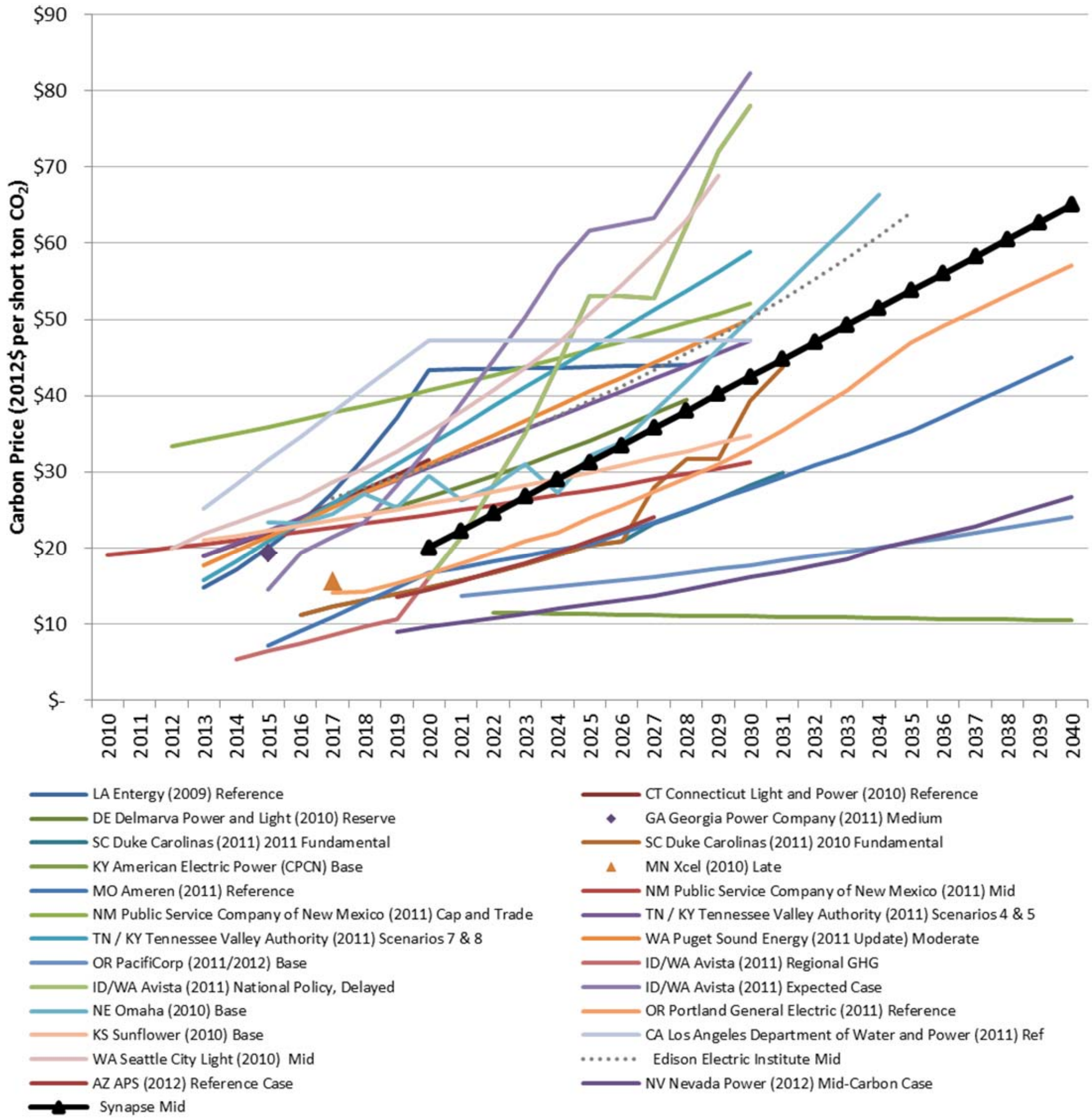


Figure 11 overlays the Synapse High case and the high case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (now shaded in grey). Not all IRPs that provide mid-level forecasts also provide high forecasts. The high cases generally reflect a nearer-term policy start date, as well as a more rapid rate of increase in prices with time. The Synapse forecast starts later than most, and rises from \$30/tCO_2 in 2020 to \$90/tCO_2 in 2040.

[26] Legend given here is common to all subsequent utility price forecast charts. While scenario names may change, colors are constant for a given utility.

Figure 11: Synapse High forecast as compared to the High and Mid forecasts of various utilities (see legend in Figure 10)

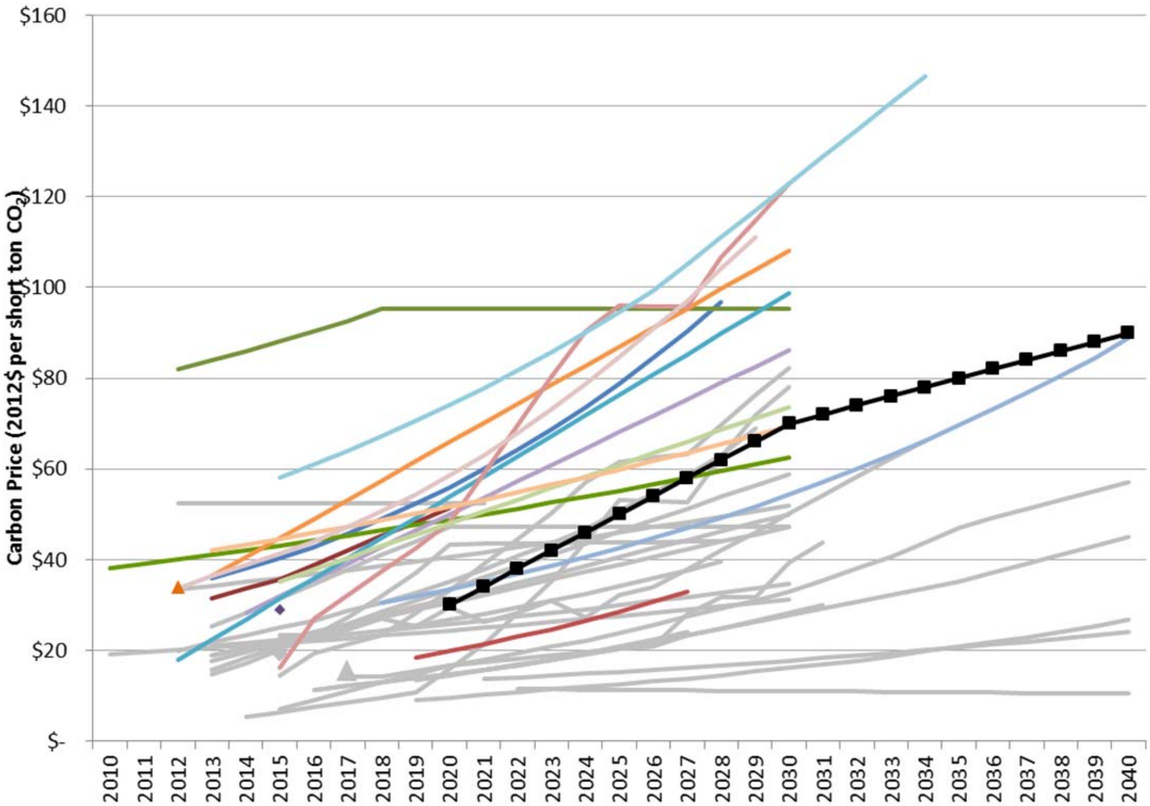


Figure 12 overlays the Synapse Low case and the low case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (shaded in grey). The low case forecasts both start at substantially lower values (occasionally at zero values), and rise at slower rates. The Synapse forecast starts later than most and rises from $15/tCO_2$ in 2020 to $35/tCO_2$ in 2040.

Figure 12: Synapse Low forecast as compared to the Low and Mid forecasts of various utilities (see legend in Figure 10)

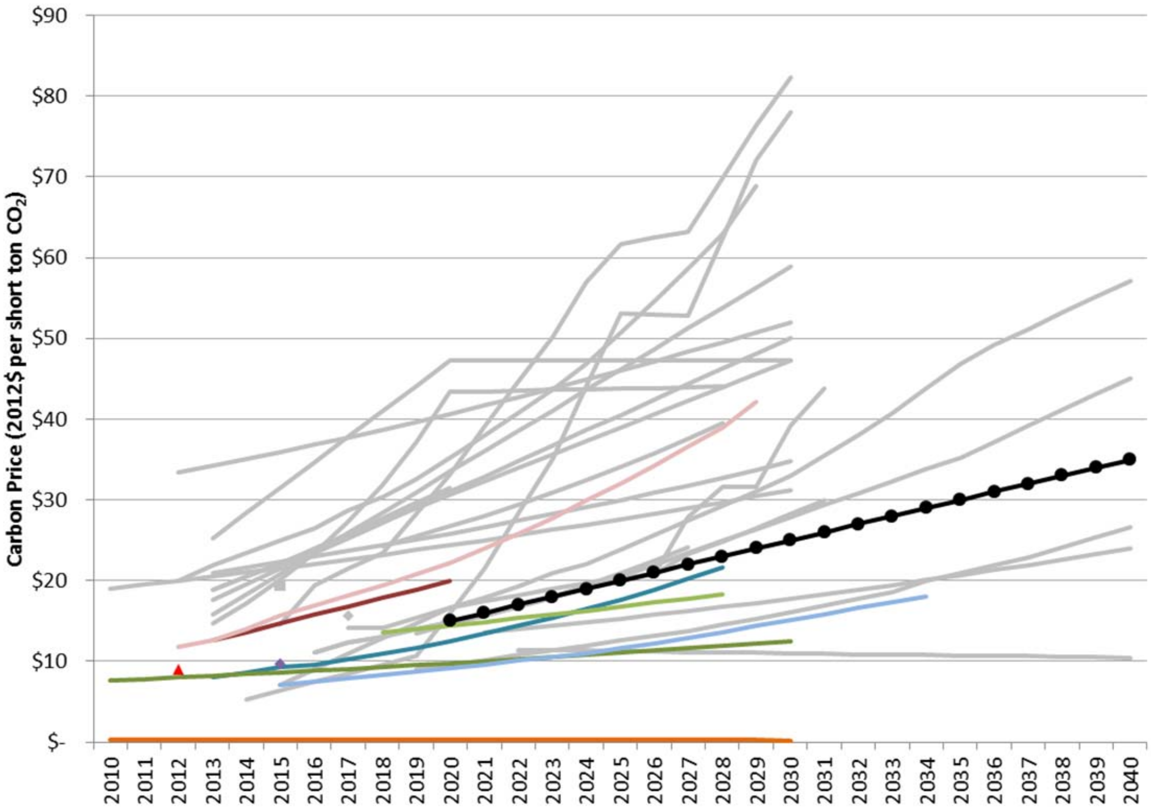


Figure 13 shows Synapse's Low, Mid, and High forecasts compared to the full range of utility forecasts shown above. The Synapse projections represent a plausible range of possible future costs. Using all three recommended price trajectories will facilitate sensitivity testing of long-term investment decisions in electric sector resource planning against likely federal climate policy scenarios.

Figure 13: Synapse forecasts compared to the range of utility forecasts

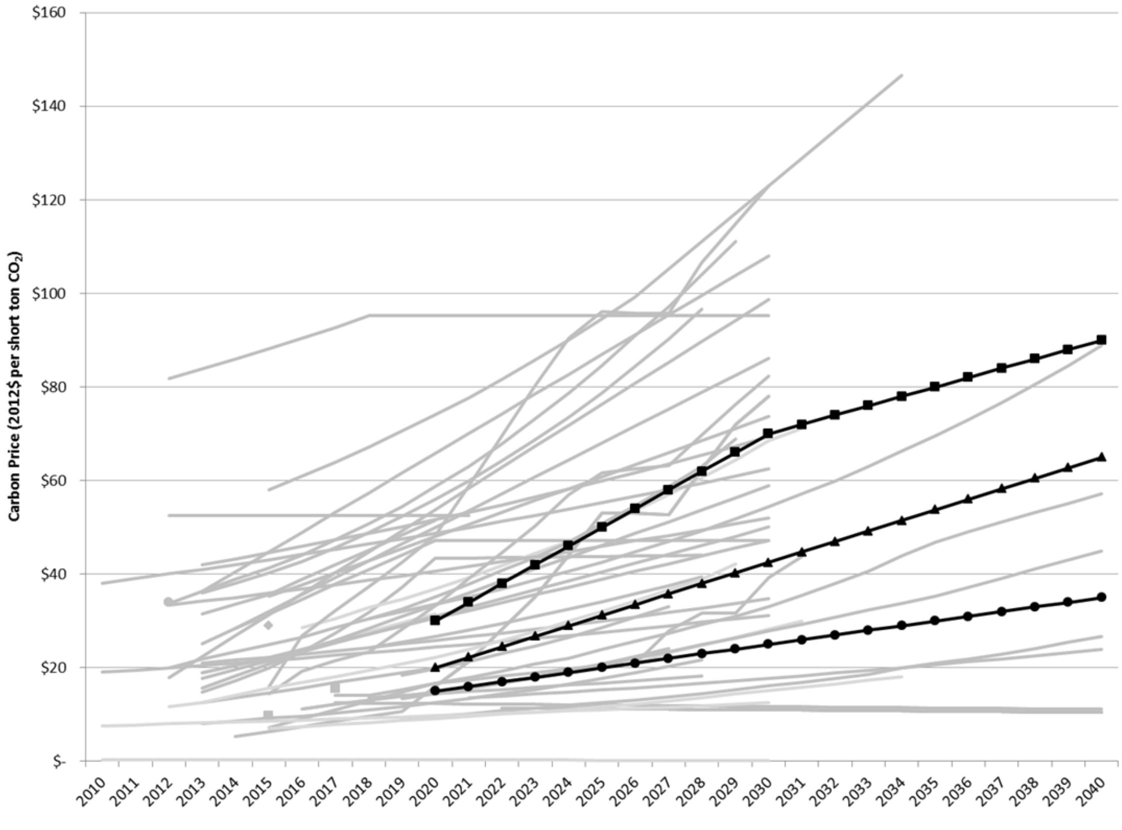
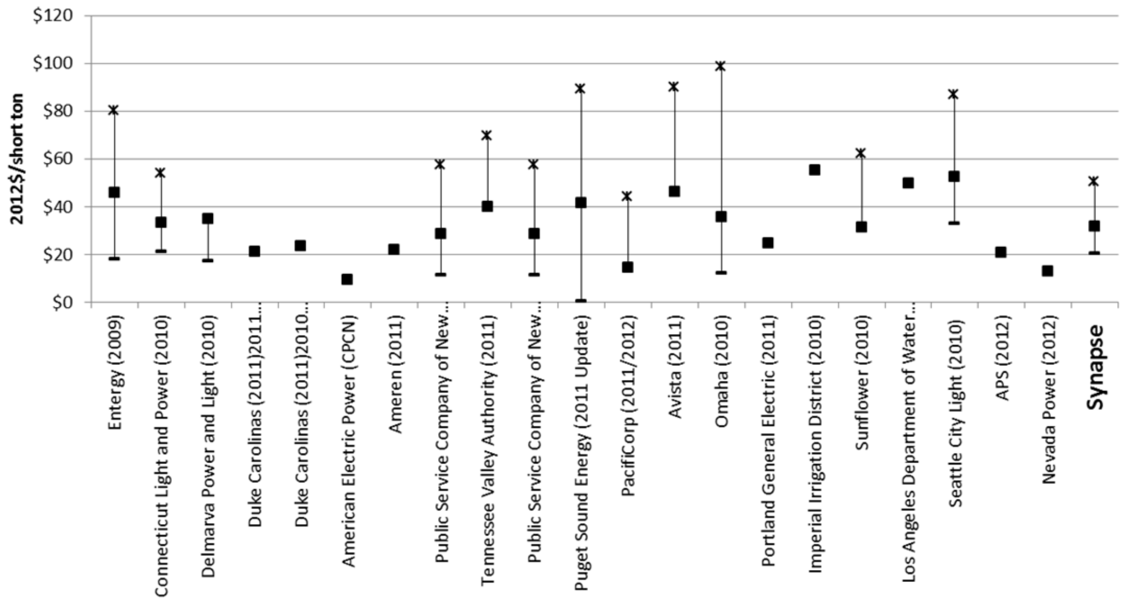


Figure 14 compares the levelized costs of Synapse's Low, Mid, and High cases to the levelized costs of utility estimates for 2020 through 2030, a period after the start and before the end of most forecasts. While levelizing between 2020 and 2030 results in different Synapse values than presented in Table 1 (where forecasts were levelized between 2020 and 2040), this approach allows for overlap and comparison with a broader range of utility estimates.

Figure 14: Levelized price of CO_2, 2020-2030, utilities and Synapse[27]



[27] All forecasts are levelized with a 5% discount rate based on CO_2 prices between 2020 and 2030. Forecasts with a price for only a single year excluded.

Appendix A: State and Regional GHG Initiatives

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation.

This appendix provides a more thorough discussion of state and regional greenhouse gas (GHG) initiatives. Collectively, these initiatives suggest that momentum is building toward more comprehensive federal GHG action.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [28]

Regional Greenhouse Gas Initiative: The Regional Greenhouse Gas Initiative (RGGI) is an effort of ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions, and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.[29] This is the first mandatory carbon trading program in the nation. Recently, allowance prices have been hitting the CO_2 price floor, as actual emissions are far below the budget of 188 mtons/year.

California: In 2006, the California Legislature passed the Global Warming Solutions Act (AB 32), which requires the state to reduce emissions of GHGs to 1990 levels by 2020. The California Air Resources Board (CARB) outlined more than a dozen measures to reduce carbon emissions to target levels in its 2008 *Scoping Plan*. Those measures include a renewable portfolio standard, a low carbon fuel standard, and a cap-and-trade program. Approximately 22.5% of the emissions reductions called for by AB 32 are estimated to occur under the cap-and-trade program. California will have the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS).

The first compliance period for the program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e per year. The second compliance period will run from 2015-2017, and the third compliance period will cover 2018-2020. During these periods, the cap-and-trade program will expand to cover suppliers of natural gas, distillate fuel oil, and liquefied petroleum gas if the combustion of their products would result in 25,000 metric tons of CO_2e or more.[30] The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015. When additional sources are added, the cap increases to accommodate them, but then increases the percentage reductions in emissions to 3% in 2016, rising to 2.5% in 2020. The state plans to allocate the bulk of allowances for free in 2013, but will gradually auction

[28] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

[29] The ten states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results is available on the RGGI Inc website at www.rggi.org

[30] §95812 (d)(1), page 48

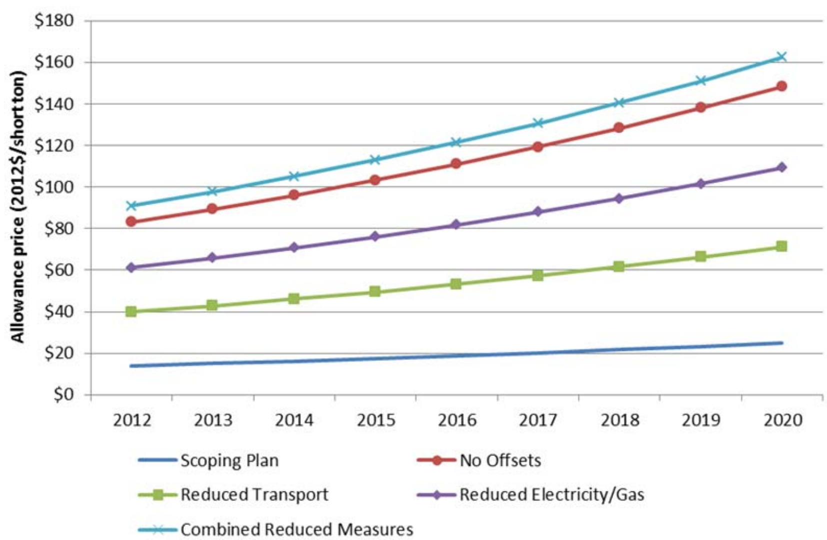
an increasing number of allowances between 2013 and 2020. Banking[31] and offsets[32] are both allowed under the California program.

The state of California has set a floor price for allowances beginning at $9.1/ton in 2013 ($10/metric tonne), and rising annually by 5% plus the rate of inflation.[33] In 2010 the Air Resources Board modeled the CO_2 allowance price trajectory that would enable reduction targets to be met under the following five cases:

1. Scoping Plan: Implements all of the measures contained in CARB's *Scoping Plan*
2. No Offsets: Does not allow offsets in the cap-and-trade program
3. Reduced Transport: Examines less effective implementation of the transportation-sector measures
4. Reduced Electricity/Gas: Examines less successful implementation of the electricity and natural gas measures
5. Combined Measures Reduced: Examines less successful implementation of transportation, electricity, and natural gas measures[34]

These five cases represent different scenarios of regulatory programs which, although different from the cap-and-trade program, can simultaneously help to achieve the goals of cap-and-trade. These regulatory measures are known as complementary policies. Figure A-1 shows the allowance price trajectories associated with those five cases.

Figure A-1: AB 32 Modeled Allowance Price Trajectories[35]



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[31] §95922 (a), page 151
[32] §95973 (a)(2)(C), page 156
[33] §95911 (b)(6), page 129
[34] California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. Page ES-6.
[35] Id. Page 40.

As shown in Figure A-1, when the policies that are complementary to the cap-and-trade program are less effective, greater CO_2 reductions need to occur under the cap-and-trade program, and the allowance price is much higher. Similarly, the availability of offsets lowers the allowance price in the cap-and-trade program, as compliance with reduction targets can be met with offsets. This allows banking of allowances in the beginning of the program, which can keep allowance prices lower in later years.

California's first allowance auction is scheduled for November 14. A trial auction was completed on August 30, and more than 430 entities that will be regulated under the cap-and-trade program were invited to participate. CARB does not plan to release a settlement price, but on the date of the test auction, futures for December 2013 were trading at $14.77/ton, and forward contracts had sold for $14.77 and $14.82/ton.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[36] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[37] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[38]

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. These policies require electric utilities and other retail electric providers to supply a specified minimum amount—usually a percentage of total load served—with electricity from eligible resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

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[36] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan
[37] Minnesota Statutes 2008 § 216B.241
[38] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

In general the goal of an RPS policy is to increase the development of renewable resources by creating a market demand. Increasing demand makes these technologies more economically competitive with other less expensive, but polluting, forms of electric generation. Many other policy objectives drive the adoption of an RPS or renewable goal, including climate change mitigation, job creation, energy security, and cleaner air.

The impact of an RPS on CO_2 emissions is dependent on factors such as:

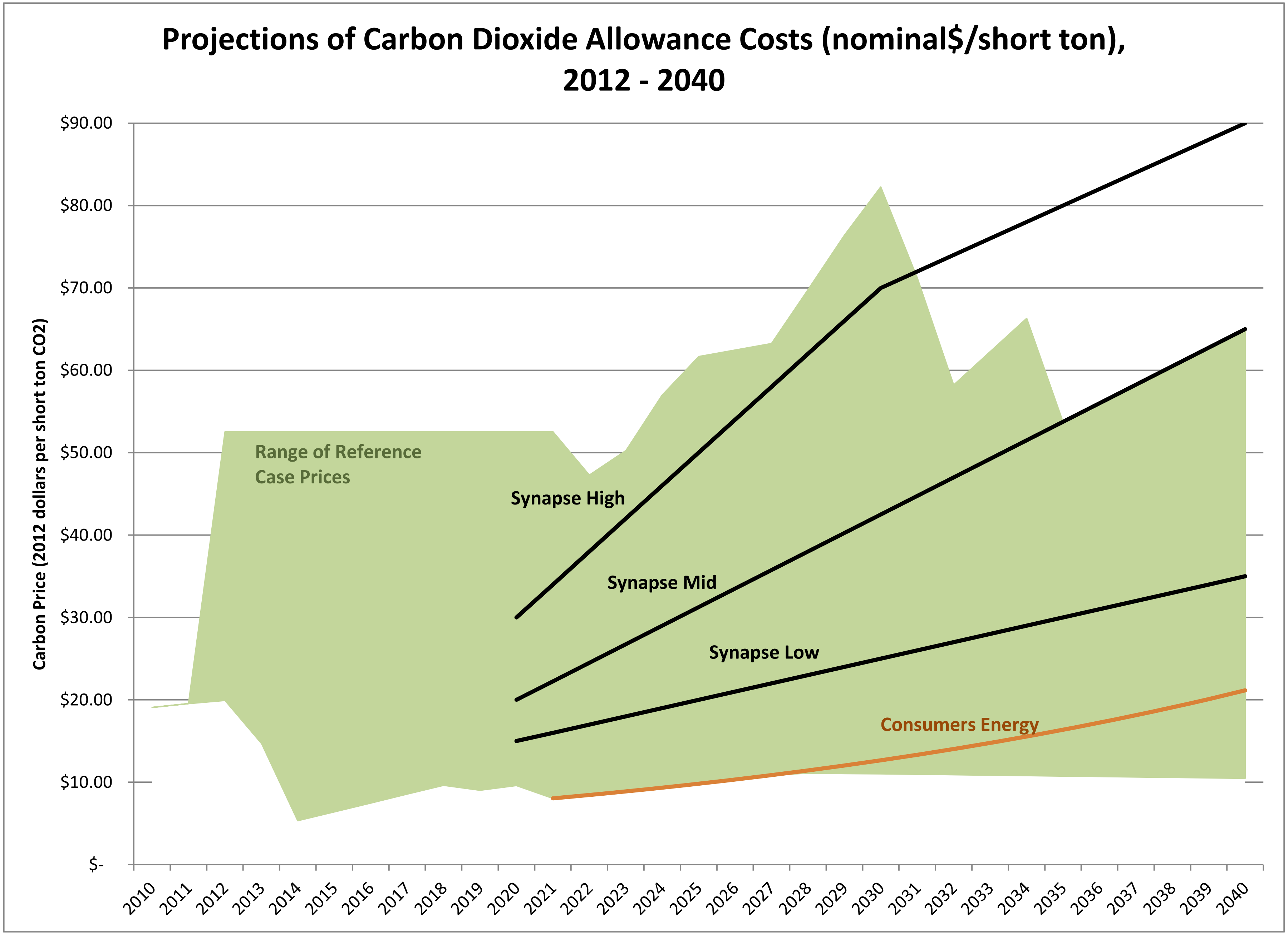
- the types of resources that are eligible to meet the standard,
- the target level set by the RPS,
- the base quantity of electricity sales upon which the standard is set,
- how renewable energy credits (RECs) or attributes are tracked or counted,
- how RECs are assigned to different resources,
- banking, trading and borrowing of RECs,
- alternative compliance options, and
- coordination with other state and federal policies.

Currently, 29 US states have renewable portfolio standards. Eight others have renewable portfolio goals.

In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories; greenhouse gas registries; climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI, requiring specific emissions reductions from power plants in the state, and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

Hawaii, while not part of a regional climate initiative, has an even more aggressive RPS, seeking to achieve 40% renewable energy by 2030, coupled with an Energy Efficiency Portfolio Standard with the goal of reducing electricity use by 4,300 GWh by 2030. After 2013, 2% of electricity revenues in Hawaii will go towards a Public Benefit Fund, an independent entity tasked with promoting and incentivizing energy efficiency measures across the state.


Projections of Carbon Dioxide Allowance Costs (nominal$/short ton), 2012 - 2040
Carbon Price (2012 dollars per short ton CO2)
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
2010
2011
2012
2013
2014
2015
2016
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2039
2040
Range of Reference Case Prices
Synapse High
Synapse Mid
Synapse Low
Consumers Energy

17087-MEC-CE-88

Question:

39. Refer to the direct testimony of David Ronk: Produce the study of the conceptual gas infrastructure requirements and costs to support the replacement of the remaining five coal-fueled generating units located at the Campbell and Karn plant sites with natural gas-fueled combined cycle generating plants.

Response:

Beginning on page 24, line 1 and ending on page 26, line 8, of the direct testimony of David Ronk, the impact of replacing the remaining five coal-fueled electric generating units with natural gas fueled combined cycle electric generating units on the gas transmission system infrastructure is discussed.

The following documents are provided:

1. Spreadsheet titled "Potential Gas Infrastructure Costs – Campbell and Karn Coal to Gas Conversion", dated August 8, 2012.
2. Spreadsheet titled "2013 Electric Rate Case – Lateral Study", dated August 8, 2012.

(NOTE: Attached are numbered documents 08700941 through 08700943.)

David F. Ronk, Jr.
December 7, 2012

Transactions and Wholesale Settlements Department

Potential Gas Infrastructure Costs
Campbell and Karn Coal to Gas Conversion

	Conceptual Costs ($ million)	
INSTALLED PIPELINE AND MEASUREMENT COSTS	**Campbell**	**Karn**
Pipeline	$124	$267
Measurement & Regulator Station	$5	$4
TOTAL PIPELINE & MEASUREMENT	**$129**	**$271**
Diameter	24 inch	26 inch
Mileage	20 miles	45 miles
$ Million per Mile[1]	$6	$6
INSTALLED COMPRESSION COST: GREENFIELD SITE		
Greenfield Compressor Station	$71	
2 Compressor Units @ 4750 hp each	$16	
TOTAL GREENFIELD SITE	$87	
GREENFIELD[1]: $ million per 1000 hp	**$9**	=87/(4750*2)*1000
INSTALLED COMPRESSION COST: EXISTING SITE		
White Pigeon Plant 3 with 16,575 hp (in-service)	$72	
Ray Plant 3 with 23,675 hp (construction in progress)	$175	Current forecast
TOTAL EXISTING SITE	$247	
EXISTING[2]: $ million per 1000 hp	**$6**	=247/(16575+23675)*1000

Assumptions:
- Campbell gas demand is 7000 MMBtu/d or 168 MMcf/d to serve 1200 MW
- Karn incremental gas demand is 3500 MMBtu/d or 84 MMcf/d to serve 600 MW
- Pipeline sizing minimizes lateral pressure drop
- All estimates are conceptual
- All estimates in 2012 dollars
- Direct pipeline and compression costs include 50% contingency
- Pipelines built to Class III along the entire pipeline route
- Does not include environmental, right of way, land, or condemnation contingency costs
- Measurement and Regulation station estimate based on recent conceptual estimates and historical costs and includes primary and secondary measurement and regulation, heater and filter separator
- Greenfield compressor station analysis includes one spare
- 4750 hp units designed to 400 psig suction to 960 psig discharge & rates up to 250 MMcf/d per unit

Notes:
[1]Does not include any estimated overhead costs
[2] Compression at existing site based on average of CECo White Pigeon Plant 3 and Ray Plant 3 costs

Date: 8/8/2012

17087-MEC-CE-54

Question:

5. Describe in detail the types of expenses to be included in the "mothballing" category added to Exhibit A-28 in 2013.

Answer:

5. Exhibit A-28 (DBK-3) identifies $1.9M for mothballing in 2013. This amount is largely engineering work associated with determining the detailed activities on a site-by-site basis needed to mothball the units.

David B. Kehoe

David B. Kehoe
November 26, 2012

Electric Generation & Plant Operations

17087-MEC-CE-82 (partial)

Question:

33. Refer to testimony of David Ronk; refer to page 14 line 19 through page 15 line 2 of your testimony.

a) What are the company's current expectations regarding the relative future costs of gas and coal?

b) Has the company determined what the relationship between the future price of gas and coal would need to be in order for the company to decide to bring any or all of the mothballed units back into service after 2015?

c) For each of the seven classic units, identify what controls or other steps you currently expect would be needed to achieve air quality, water quality, and coal combustion waste regulatory compliance if the units were to be brought back into service.

d) For each of the seven classic units, identify the cost per year of keeping the unit in mothball status. This question seeks the total cost as well as a breakdown by category.

Response:

a) The Company's forecast of future costs of gas and coal are included in Attachment 1 to 17087-MEC-CE-78.

b) Yes. The company has determined that the equivalent gas price that would be necessary to result in the approximate identical revenue requirement as would be incurred if the seven coal-fueled electric generation units were modified to remain in service with appropriate emission controls to be approximately 75% higher than the company's estimate of natural gas prices available in late October 2011. The Company's forecast of natural gas prices available in late October 2011 is provided in Attachment 1 to 17087-MEC-CE-78.

c) Witness Nancy Popa addresses the control technology that would be required to achieve air quality, water quality, and coal combustion waste regulatory compliance if the seven coal-fueled electric generating units were to remain in service in response to 17087-MEC-CE-59.

d) David Kehoe provides a response to this question.

David F. Ronk, Jr.
December 12, 2012

Transactions and Wholesale Settlements Department

17087-MEC-CE-318

Question:

32. Refer to the direct testimony of Nancy A. Popa at page 23, lines 8-11, and to Attachment 1 to response 17087-MEC-CE-78.

(a.) State whether the Company has developed any cost estimates for installing cooling towers on its coal-fired plants to comply with Clean Water Act Section 316(b).

(i.) If so, please identify and produce such estimates and supporting workpapers to the extent not already produced in this case.

(ii.) If not, explain why not.

Response:

(a.) Yes.

(i.) Attached are summaries of the cooling tower estimates for the Campbell and Karn sites which were developed using information provided in a 2010 EPRI Cooling Tower Retrofit Cost Study, also attached.

(NOTE: Attached are numbered documents 08702020 through 08702186.)

Nancy A. Popa

Digitally signed by Nancy A. Popa
Date: 2013.01.16 08:28:05 -05'00'

Nancy A. Popa
January 14, 2013

Environmental Services Department

Attachment 1 to 17087-MEC-CE-318

Closed-Cycle Retrofit Study

Capital and Performance Cost Estimates

[Product ID #]

Final Report, September 2010

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Arkansas Electric Cooperative
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Dairyland Power
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Exelon
FirstEnergy Services
Great River Energy
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Minnesota Power
Mirant
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Closed-Cycle Retrofit Study: Capital and Performance Cost Estimates. EPRI, Palo Alto, CA <and Name of Cosponsor(s), if any>: 2010 <Product ID Number>.

CONTENTS

APPENDICES

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION

This report presents the results of an analysis of the costs of retrofitting with closed-cycle cooling systems those existing steam-electric power plants, which were designed for, built with, and are currently operating on once through cooling. The motivation for this and earlier studies has been regulatory activity subsequent to Section 316(b) of the U.S. Clean Water Act (1-1)[1] in which consideration has been given to requiring all once-through cooled plants to retrofit closed-cycle cooling equipment. The primary objective of this analysis is to develop an estimate of the national capital cost and associated operating and maintenance costs and plant efficiency penalties of implementing closed-cycle retrofits on all applicable units.

Background

Legislative and regulatory history

In 1972, Congress amended the Clean Water Act (CWA) to regulate cooling water intake structures; specifically, to require that "the location, design, construction and capacity of cooling water intake structures shall reflect the best technology available for minimizing adverse environmental impact." (1-2). EPA's first attempt to promulgate regulations under 316(b) was remanded by the Fourth Circuit court in 1977 on procedural grounds. No new rule was issued for many years until the Agency, under a consent decree, established a schedule for issuing rules in three phases; namely, Phase 1: New Facilities; Phase II, existing power plants; Phase III, Existing plants, including power plants, not covered by Phase II and other industrial facilities. This study is not related to any aspects of Phase I or Phase III.

The Phase II rule addressed existing facilities which are the subject of this study and was issued on July 9, 2004 (1-3). The rule was challenged by a number of environmental groups led by Riverkeeper, Inc. as well as several state environmental agencies, power companies and the Utility Water Act Group. The challenges were consolidated into a single case which was argued before the United States Court of Appeals for the Second Circuit on June 8, 2006 and a decision was issued on January 25, 2007.

One of the major issues in the case was the role of cost in determining "Best Technology Available" (BTA). The decision (1-4) rejected the use of "cost-benefit" analysis. This aspect of the case was appealed to the U. S. Supreme Court (1-5). The appeal was granted, and the case was argued on December 2, 2008. The Supreme Court issued its

[1] **References listed in order within each chapter; i.e., (Chap. #-Ref. #). Complete citation lists are at the end of each chapter.**

decision on April 1, 2009 (1-6) and determined that EPA could consider benefits relative to cost in making the BTA determination.

The Second Circuit Decision said that, while consideration of cost/benefit could not be used to reject closed-cycle cooling retrofits as BTA, retrofits could be rejected if the industry could not bear the cost or if there were significant adverse environmental impacts or impacts to energy production and efficiency.

In response to the Second Circuit Decision, EPA issued a memorandum dated March 20, 2007, to EPA's Regional Offices announcing withdrawal of the §316(b) Phase II Rule. This was followed by a notice in the Federal Register on July 9, 2007. Specifically, the memorandum and Federal Register notice stated the withdrawal of the Rule was a result of the Decision's impact on the overall compliance approach. EPA determined that so many of the Rule's provisions were affected by the Decision that the overall Phase II approach was no longer workable for compliance. The memorandum and Federal Register notice further directed EPA Regional Offices and delegated states to implement §316(b) in NPDES permits on a BPJ basis, until the Decision issues are resolved. EPA then assembled a team to initiate work on a revised Section 316(b) regulation based on the Second Circuit Decision.

Since EPA has said that, in revising the Rule, it will focus on an evaluation of BTA including use of closed-cycle cooling, EPRI initiated a research program to inform the rulemaking on the implications of issuing a Rule requiring closed-cycle cooling retrofits based on the factors the Second Circuit ruled were allowed to consider and subsequent to the Supreme Court Decision the benefits relative to the cost. Fundamental to determining if industry can bear the cost of retrofits, impacts to energy production and efficiency and benefits relative to the cost is knowledge of the costs of retrofits for affected Phase II facilities.[2] That is a major objective of this report. Additional objectives are to provide a better understanding of the impacts to energy production as a result of energy requirements of closed-cycle cooling systems or facility outages required for retrofits.

Prior studies

Throughout the period of legislative, regulatory and judicial activities summarized above, a number of studies have been conducted. These studies have recognized, as did the regulatory process, significant differences between the application of closed-cycle cooling at new plants and the retrofit of existing plants from once-through to closed-cycle cooling. Those differences are of major importance in both the design and construction phases.

The design issues are related to the fact that closed-cycle cooling usually provides warmer cooling water and hence higher turbine exhaust pressures than does once-through

[2] For the current Rulemaking, the EPA has combined consideration of what had been Phase II and Phase III facilities into a single category called "Existing Facilities". For the purpose of this study, the analyses will consider only those facilities formerly included under the Phase II categorization

cooling. Therefore, if a plant is designed originally for closed-cycle cooling, the selection of the turbine, the condenser and other major plant components will be made to accommodate the turbine exhaust pressure for that system while still providing the desired plant capacity at acceptable efficiency. A closed-cycle cooling system retrofit to an existing plant with a turbine, condenser and other components originally selected for different conditions will usually incur efficiency and capacity penalties.

Similarly, the installation and construction is typically far more difficult for retrofits at existing plants than for new plants at "greenfield" sites. Primary difficulties are a lack of available space close to the existing turbine halls for cooling towers and the presence of numerous, on-grade, underground and overhead interferences to the installation of circulating water lines between the existing condenser and the new cooling tower. These factors, while entirely site-specific, can, and typically do, result in cooling system retrofit capital costs which are significantly higher than the expected cost for a comparably sized system at a new plant.

Studies by both Federal and State agencies and by industry under the direction of the Utility Water Act Group (UWAG) and the Electric Power Research Institute (EPRI) or by individual plants have attempted to estimate the capital and performance costs of such retrofits.

Federal studies include the original development documents assembled as part of the Phase I and Phase II Rule makings (1-7, 1-8) by EPA and a supporting study by the U.S. DOE (1-9). The State of California sponsored an analysis of the cost of retrofit of ocean plants. (1-10).

Industry studies include two by UWAG: one by the Washington Group (1-11) and one by the Stone & Webster Engineering Corporation (1-12). EPRI has sponsored two cost studies prior to this one: The first, in 2002, submitted as part of the original Phase II Rulemaking process (1-13); the second in 2005 specifically directed at California ocean plants. (1-14). Also, an interim report (1-15) on the present study was submitted to EPA in May, 2008 to assist in informing the on-going development of revised regulations in response to the remand of the original Phase II rule by the Second Circuit Court of Appeals.

This study is part of a larger, comprehensive effort by EPRI which consists of four separate studies. The complete project includes:

1. Estimation of the cost of retrofitting Existing Facilities facilities with closed-cycle cooling (Maulbetsch Consulting)
2. Determination of impacts to energy production and supply by quantification of the number of facilities/Units/MW at risk of closure and the loss of MW due to retrofitting (Veritas Economic Consulting)
3. Quantification of the adverse environmental and social impacts associated with closed-cycle cooling compared to impingement and entrainment losses (URS Corporation)

4. Identification of impacts to transmission system reliability and electric power supply based on results of the second project (Veritas Economic Consulting and PwrSolutions)

Scope

This study develops an estimate of the national cost of retrofitting with closed-cycle cooling systems all electric power plants which had been classified as "Phase II facilities" under Section 316(b) of the Clean Water Act. There are approximately 446 power plants in the U.S. at which all or some of the units are operating on once-through cooling with cooling water intake structures which had been classified as "Phase II Facilities" for purposes of regulation under Section §316(b) of the Clean Water Act (1-1). These plants are listed in Appendix A.

The project consists of several tasks beginning with the development of a methodology for cost estimation in which a range of expected retrofit costs for plants of different types and cooling systems of given capacity is established. Then for an individual plant, its expected position within that cost range is determined based on an estimated "degree of difficulty" of the site-specific retrofit. Subsequent tasks include the identification and acquisition of extensive cost data from actual retrofits and cost estimates from planned retrofits, the development of correlations which define the expected range of costs, and the solicitation of site-specific information from all of the Existing Facilities on which to base the "degree of difficulty" for each.

Many of the plants solicited provided some or all of the information requested. From those plants, a group of plants is selected which best represents the complete family of Existing Facilities by having a similar distribution of plant size, plant type, source water type and geographical location. Plant-specific estimates are made of the degree of difficulty and the corresponding retrofit capital cost for that group of plants. These estimates are then validated by comparison to any available independent cost estimates. These results from these selected plants are then extrapolated to the complete family of Existing Facilities and general qualitative estimates are made of the probable national cost of retrofitting all applicable Existing Facilities.

In addition to the capital cost of retrofitting the plant cooling system, there are other costs resulting from the effects of the retrofit. Major items include the cost of any increased operating power or maintenance requirements, the cost of reduced plant efficiency and capacity due to increased turbine exhaust pressure and the cost of replacement energy which must be provided to the power grid during periods when the plant cannot operate because of retrofit project construction activities. These costs are estimated for a variety of site-specific situations, generalized and extrapolated to an estimate of the total magnitude of those effects on the Nation's electric power grid.

Organization of report

The remainder of this report is organized as follows.

Chapter 2 contains a detailed description of the approach adopted in the study. That description includes a complete explanation of the "degree of difficulty" concept and its relationship to cost correlations based on independent cost information from actual and planned retrofits. Also, the set of closed-cycle cooling retrofit technologies considered or excluded from consideration for use in retrofit applications is discussed.

Chapter 3 reviews the independent cost data, the sources from which they were obtained and the development of the cost correlations which establish the expected cost range. Plants for which independent cost data were available are listed in Appendix B.

Chapter 4 describes the factors used to establish the degree of difficulty of retrofit at individual sites and the approach taken to acquiring site-specific information on these factors from as many of the existing facilities as possible. Plants for which site-specific information was provided are listed in Appendix C.

Chapter 5 summarizes the results of site-specific analyses of 100 plants selected to be as representative as possible of the family of 444 Phase II facilities. Particular attention is paid to detailed descriptions of the retrofit project at 9 plants for which either actual costs or very detailed and thoroughly documented costs are available. Appendix D lists the plants for which site-specific analyses were conducted. Appendix E contains brief write-ups of each plant.

Chapter 6 compares the results of estimates using the methodology developed in this study to those plants for which both site-specific information from which estimates could be made and independent cost information was available. The validity and reliability of the methodology is evaluated on the basis of these comparisons.

Chapter 7 provides a discussion of and some estimating methods for those retrofit costs that are not captured in the simple capital costs of retrofit. These include operating power cost for circulating water pumps and cooling tower fans, cooling tower maintenance costs, the costs of efficiency and capacity penalties imposed on the plant by cooling system limitations, and other related costs incurred as a result of a cooling system retrofit, such as licensing and permitting costs.. The discussion presents and explains the methodology for each category of costs and presents some illustrative examples.

Chapter 8 presents estimates of the potential cost of closed-cycle cooling system retrofit if it were to be applied uniformly on a national basis. A number of scale-up methods are proposed and evaluated for extrapolating the results of the limited set of plants for which estimates could be made with some level of confidence to the entire family of Phase II facilities in the power industry.

Finally, Chapter 9 summarizes the report and presents the major, important conclusions.

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1-2: Federal Water Pollution Control Act, §316 (b), 33 U.S.C §1326(b)
1-3: 40 CFR Parts 9, 122 – 125, Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, 69 Fed. Reg. 41,576, July 9, 2004.

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1-5: United States Supreme Court, Docket No. 07-588, 07-589 and 07-597 (Consolidated), Available at http://www.supremecourtus.gov/docket/07-588.htm), December 2, 2008.

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1-7: EPA Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule, EPA-821-R-04-007, February 12, 2004.

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1-10: *California's Coastal Power Plants: Alternative Cooling System Analysis*, Tetra Tech, Inc., Golden CO; T. Havey, Project Manager, Prepared for California Ocean Protection Council, February, 2008. (Available at http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml):

1-11: *Estimated Cost of Compliance with EPA Proposed Rule 316(b) of the Clean Water Act*, The Washington Group, International, Submitted to Hunton & Williams for the Utility Water Act Group, December, 2001.

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1-14: *Issues Analysis of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling: California Coastal Plants*, EPRI, Palo Alto, CA 2007. TR-052907

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2
Cost Estimating Methodology

Introduction

This chapter describes the general approach to the development of a national cost estimate for retrofitting closed-cycle cooling systems to existing facilities, originally designed for, built with and currently operating on once-through cooling systems. A complete list of the approximately 444 in-scope existing facilities is presented in Appendix A.

In once-through systems, cooling water is withdrawn from a natural waterbody, passed once through the power plant cooling system and then returned to the source waterbody. As illustrated in Figure 2-1a, the cooling system consists of a steam condenser, typically of the shell-and-tube type, circulating water pumps, circulating water lines, intake and discharge structures and, in most cases, some water treatment equipment, typically chlorination for biofouling control. At some plants water for cooling is stored or impounded in a reservoir, lake or pond which is constructed specifically for the plant cooling system. Although the system operates like a once-through system in that the water is withdrawn from and returned to the same waterbody, the impoundment rejects heat from its surface to the atmosphere by evaporation. Water is withdrawn from the nearby "natural" waterbodies only to replace impoundment water lost to evaporation. In that sense, the cooling system's effect on the natural waterbodies is similar to a closed-cycle system and plants with cooling ponds or reservoirs. The National Pollutant Discharge Elimination System (NPDES) permit systems provides an exemption for lakes and ponds constructed for the purpose of providing wastewater treatment prior to discharge to "Waters of the U.S." and, therefore, cooling water lakes and ponds may be exempted from 316(b) requirements. Applicability of requirements 316(b) requirements varies depending on a number of factors such as use of the lake or pond for other purposes or whether it was created by use of a dam or impoundment on an existing stream.

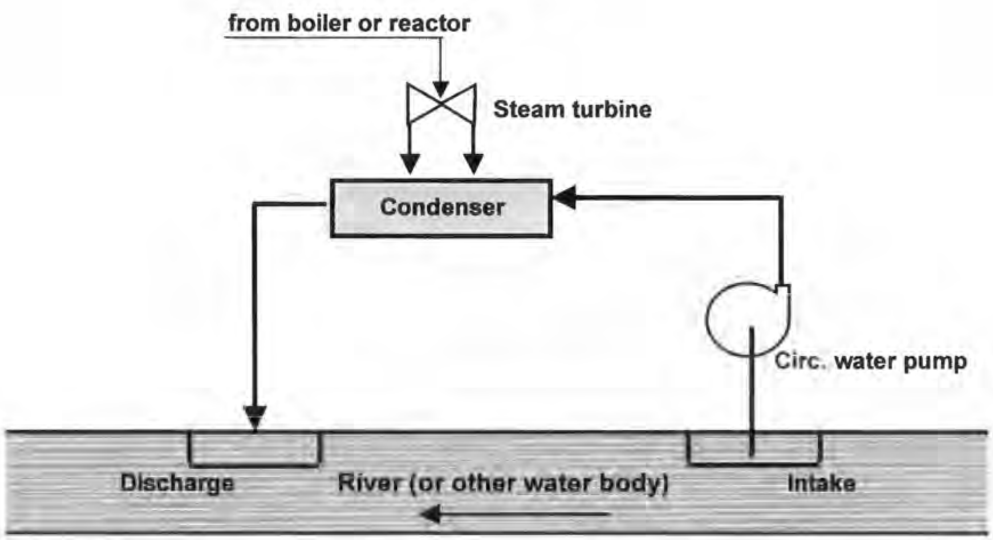

Figure 2-1a: Schematic of once-through cooling system

Closed-cycle (or recirculating) wet cooling systems are similar to once-through cooling in that the steam is condensed in a water-cooled, shell-and-tube steam condenser, but differ in that the heated cooling water is not returned to waters of the U.S. but is conveyed to a cooling component, typically a wet cooling tower (other options include cooling ponds, spray enhanced ponds, spray canals, etc.) where it is cooled and then recirculated to the condenser. A typical closed-cycle wet cooling system is shown schematically in Figure 2-1b.

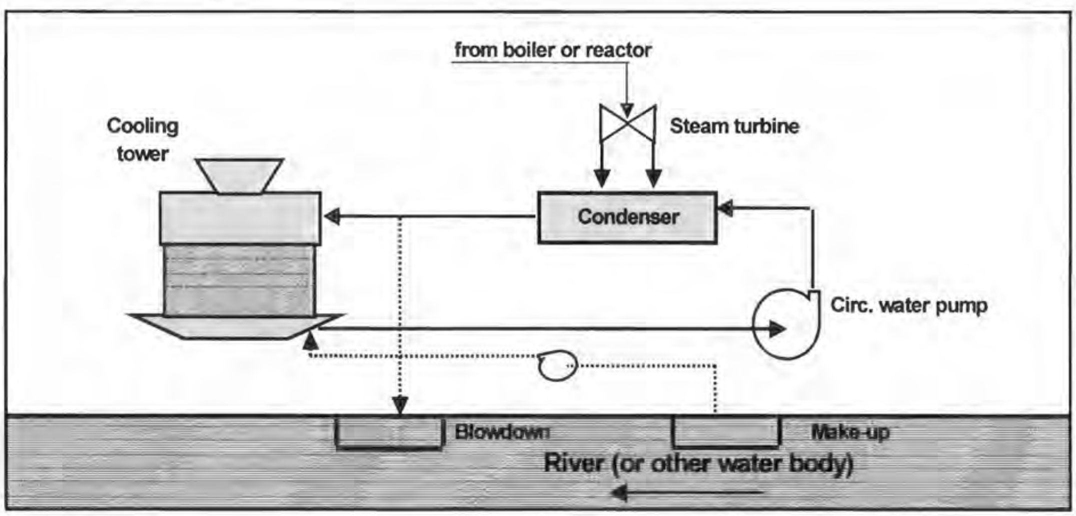

Figure 2-1b: Schematic of closed-cycle wet cooling system

The significant difference in the context of this study is that the amount of water continuously withdrawn from the natural waterbody is significantly greater for once-through systems. As will be discussed in greater detail in Chapter 3, typical withdrawal rates for once-through cooling range from 400 to 700 gallons per minute (gpm) for each megawatt (MW) of plant generating capacity. Alternatively, closed-cycle systems withdraw only enough water to replace that lost by evaporation to the atmosphere and blowdown to the environment; typically 10 to 15 gpm per MW or approximately 2 to 5% of that withdrawn by once-through cooling. It is noted, however, that closed-cycle cooling systems consume most of the water that they take in through evaporation to the atmosphere. In fact, water consumption, as opposed to withdrawal, in closed-cycle systems is actually greater than it is for once-through cooling for a given heat load.

Figures 2-2 illustrates a basic approach taken in retrofitting closed-cycle cooling systems.

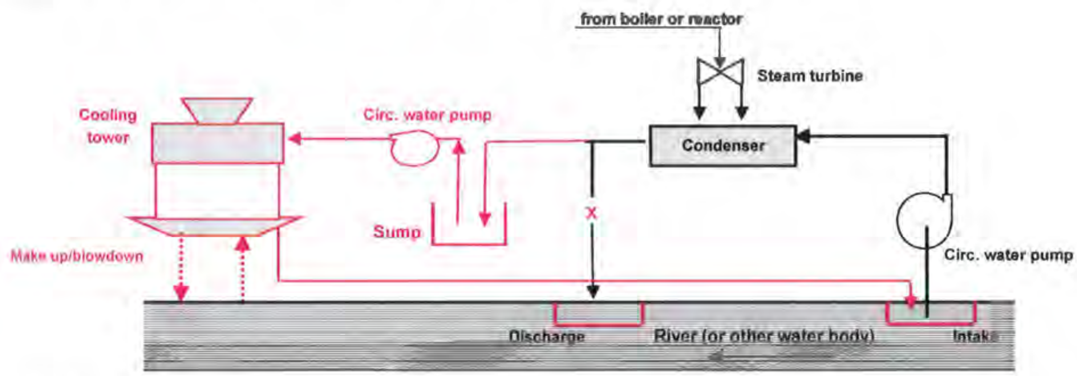

Figure 2-2: Basic approach to retrofit

The existing once-through cooling arrangement in most cases is left largely intact with the same condenser, the same set of circulating water pumps and intake discharge lines and operates at the same circulating water flow rate. However, the existing intake and discharge facilities are modified or eliminated. The hot water from the condenser is discharged into a sump from which a new set of circulating water pumps draws the hot water and pumps it to a new cooling tower. The cold water from the cooling tower then drains by gravity from the cold water basin back to an intake bay from which the original circulating water pumps draw water to be pumped to the condenser. Provisions for both makeup and blowdown from the closed-cycle system must be made to replace water lost by evaporation and blowdown to control the buildup of suspended and dissolved solids in the cooling loop.

Many variations on this retrofit arrangement are possible. Depending on the existing type of intake and discharge systems, it may be possible to use existing intake or discharge bays or canals in place of a new sump for the withdrawal and discharge points of the new circulating water loop to and from the tower. In some cases, it is possible to modify the existing circulating water pumps so that the cooling water can be pumped through the condenser and then directly to the top of the tower without the need for a second set of pumps or an intermediate sump. In some cases, it may not be possible to find a location for the tower which permits gravity return of the cold water. In that case, additional return pumps would be required. However, all of these modifications retain the basic premise of the retrofit; i.e., that the existing condenser and cooling water flow rate are retained and a cooling tower is, in some sense, simply inserted into an existing cooling loop in order to recirculate cold water to the condenser and, by so doing, to significantly reduce the continuous withdrawal rate of water from the environment.

Significantly different approaches to closed-cycle cooling system retrofits are possible. Some examples include the use of natural-draft cooling towers in place of mechanical-draft towers, the use of dry cooling in place of wet cooling and a complete re-optimization of the existing system to a different cooling water flow rate and condenser configuration. These options and their relationship to the general conclusions of the study will be discussed in later sections.

General Approach

As noted earlier, the primary objective of this study is to develop the national costs and the effects on plant efficiency and capacity from retrofitting closed-cycle cooling systems to the family of existing facilities. The general approach to conducting the study to achieve this objective consisted of several steps.

Cost determination

Independent cost information

The initial step was to assemble all available independent retrofit cost information to establish the probable range of costs. An earlier EPRI study (2-1) had collected cost data on 58 plants by soliciting information from individual utilities through UWAG and from reports by DOE (2-2, 2-3). In the current study, additional information was obtained from both new and updated estimates by utilities. Independent cost estimates for 79 plants were obtained and are listed in Appendix B.

The data were sorted and examined to find consistent trends with plants, source water and site characteristics. The general trend of costs show an increase with increasing plant size or circulating water flow as would be expected, but very large cost differences exist at all levels of plant size and flow rate. Therefore, correlations were developed for four levels of lower, intermediate and higher cost retrofits. Separate correlations were developed for fossil and nuclear plants. The analyses of the data and the development of the resulting correlating equations are described in detail in Chapter 3.

Site-specific characteristics

After observing the wide variation in cost for retrofitting plants of comparable size, it was assumed that the variation in costs corresponded, in a general way, to retrofit projects of varying degrees of difficulty. They were characterized as "Easy", "Average" and "Difficult". Based on discussions with plant personnel and architect-engineering firms and the application of professional judgment, the list of 11 factors given in Table 2-1 was compiled which were believed to be the important influences which determine the site-specific degree of difficulty.

Table 2-1: Site-specific factors affecting the cost of retrofit

Factor	Description
1	The availability of a suitable on-site location for a tower
2	The separation distance between the existing turbine/condenser location and the selected location for the new cooling tower
3	Site geological conditions which may result in unusually high site preparation or system installation costs
4	Existing underground infrastructure which may present significant interferences to the installation of circulating water lines
5	The need to reinforce existing condenser and water tunnels
6	The need for plume abatement
7	The presence of on- or off-site drift deposition constraints
8	The need for noise reduction measures
9	The need to bring in alternate sources of make-up water
10	Any related modifications to balance of plant equipment, particularly the auxiliary cooling systems, that may be necessitated by the retrofit
11	Re-optimization of the cooling water system or extensive modification or reinforcement of the existing condenser and circulating water tunnels

Examination of these factors at an individual plant leads to a judgment of whether a retrofit at that plant would be easy, average or difficult. In principle, each of the Phase II facilities could be examined, ranked as to degree of difficulty and a cost assigned from the low, average or high cost correlations. Clearly an on-site examination or even a detailed telephone discussion of the factors at each plant would require effort and expense well beyond the scope of this study. Therefore, a "cost estimating worksheet" (the worksheet) was constructed which asked questions and requested data, drawings or other information relevant to the evaluation of each of the important factors on the list. The worksheet was distributed to the industry through major trade associations that included EPRI, EEI, UWAG, NERA and APPA with a request that it be completed and returned for each once-through cooled facility owned by the Company. From the worksheets which were returned and contained adequately complete information, 125 plants were selected for site-specific analysis. (See list in Appendix D) The process of acquiring and cataloging the results from these worksheets is discussed in Chapters 4 and 5.

Concurrently, nine plants were identified for which either actual retrofit costs or detailed cost estimates produced by professional engineering firms with extensive power plant construction experience were available. For these sites, sufficient detail was obtained on plant/site characteristics and the cost breakdown among the many elements of the project cost to enable the development of insight into the influence of many of the factors listed in Table 2-1 on the total project cost. Analyses of these nine plants are summarized in Chapter 6.

The analyses of these nine cases aided in the evaluation of the 125 sites chosen for site-specific analysis based on worksheet information. Each of these 125 plants was assigned a degree of difficulty from easy to difficult. Summary write-ups for each of the plants analyzed are included in Appendix E. A review of the conclusions and trends and a categorization of the results by plant and site characteristics are given in Chapter 5.

From these ratings, a cost estimate was made for a retrofit at each plant using the correlations described in Chapter 3. In a few cases, a retrofit was considered completely infeasible at any cost. A brief discussion of the criteria used for classifying a plant retrofit as "infeasible" and a few examples of such situations are given in Chapter 4.

Two steps remained for the final estimate of the national total capital costs for retrofitting the family of Phase II facilities. The first was a test of the validity and consistency of the cost estimating methodology by comparison of the estimates with independent cost information. There are approximately 55 plants for which both independent cost information and adequately completed worksheet were available. The results of these comparisons are presented in detail in Chapter 6.

Finally, the cost estimates for the plants which were analyzed are aggregated and extrapolated to give an estimated national total cost. The extrapolation procedure is described and the results presented in Chapter 8.

Other considerations

In addition to the estimated capital cost of the retrofit which is determined as described above there are additional costs which may be incurred as a result of the cooling system retrofit. These include:

1. Additional operating power requirements and any increased maintenance costs
2. Effect of the modified cooling system on plant efficiency and capacity
3. Costs of plant "downtime" while the retrofit is being installed
4. Additional assorted costs of environmental, regulatory and licensing or permitting issues.

The approach to assessing these costs is described in the following paragraphs. A detailed discussion of the analysis and the results is given in Chapter 7

Estimate of operating power costs

A retrofitted closed-cycle cooling system using mechanical-draft cooling towers will always consume more operating power than was consumed by the original once-through cooling system. Specifically for the case of mechanical draft cooling towers, additional power is needed for the circulating water pumps to raise the water flow to the top of the tower and for the fans to draw air through the tower fill.

The amount of additional pumping power will depend on the configuration of the new circulating water circuit, the location of the cooling tower and its elevation relative to the steam condenser and the height of the tower. The additional fan power will depend primarily on the size of the cooling load and the number of cells in the cooling tower but to some degree on the design philosophy chosen for the new tower. While a detailed retrofit configuration analysis and operating power estimate for each site is beyond the scope of this study, certain generalized rules of thumb were developed which are consistent with a reasonable approach to cooling system retrofit. These estimates and the method for arriving at them are presented in detail in Chapter 7.

Estimate of effect on plant efficiency/capacity

The retrofitted closed-cycle cooling system will also, for most of the year, deliver cooling water to the condenser at a higher temperature than would be available from the natural water source used for once-through cooling. This results in a higher condensing temperature and a correspondingly higher turbine backpressure, which leads to lower plant efficiency, and reduced output. The magnitude of this effect is a function of the closed-cycle cooling system design and the climate at the site. The climatic feature of most importance is the annual variation in the difference between the original natural source water temperature and the local wet bulb temperature.

While a plant by plant analysis of the magnitude of the effect on plant capacity is again beyond the scope of this study, a general approach to estimating the magnitude of this effect is provided in Chapter 7.

Estimate of cost of downtime

The time for which the plant must be taken off-line and out of operation for the construction and installation portions of the cooling system retrofit can vary from a few weeks such that cooling tower tie in could be accomplished during a scheduled maintenance outage to several months to over a year. The length of the downtime is influenced by the complexity of the plant layout, the design philosophy adopted for the retrofit, the plant's capacity factor and operating schedule and other factors. There is relatively little information available to support generalized estimates of this cost element. A few illustrative examples are given in Chapter 7, and an approach to assigning a range of downtimes for each plant is proposed. It is recognized that this element of the cost estimate is highly uncertain as applied to any individual site.

Additional costs

Cooling system retrofits are large scale projects which influence the effect of the plant on the surrounding neighborhood and can result in environmental effects which were not present with the original once-through cooling system. A detailed analysis of the environmental trade-offs is the subject of a companion report. (2-4) However, the project may trigger a number of related licensing/permitting requirements and extensive hearings in response to actions from local intervener groups. Responding to these actions and obtaining the required permits may involve extensive time, effort and consulting assistance which can add a significant cost to the overall retrofit costs. It is beyond the scope of this project to draw any general conclusions regarding these costs, but a brief discussion with some illustrative examples is presented in Chapter 7.

References—Chapter 2

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2.3 An Investigation of Site-Specific Considerations for Retrofitting Recirculating Cooling Towers at Existing Power Plants---A Four Case Study, Parsons Infrastructure and Technology Group and the National Energy Laboratory, U.S. Department of Energy, May, 2002.
2.4 Adverse Environmental and Social Impacts of Cooling System Retrofits, EPRI Study conducted by URS Corporation, Interim Progress Report., In press.

3

Establishment of Cost Ranges and Correlations

Information Base for Cost Range and Correlations

Estimates of the cost to retrofit a once-through cooled plant to closed-cycle cooling were obtained for 79 plants. These plants are listed in Appendix B, identified by the first three digits of their Plant ID Number (from the list of Phase II facilities in Appendix A) preceded by an "F" for fossil plants and an "N" for nuclear plants. The table in Appendix B also lists the plant/fuel type, plant size, circulating water flow, source water type, plant location by state and region of the country, source of the cost estimate and the project cost expressed in March 2010 dollars. The March 2010 dollar costs are scaled from the amount and date of the original cost estimates using "Cost Construction Indices" as obtained from the Engineering News Record (3-1).

Figure 3-1 displays the capital cost of retrofits at the 79 plants vs. the circulating water flow rate. One plant (N-321) is a significant outlier and is so indicated on the plot. This plant is omitted from the development of the correlations because including it would distort the curve fit to the point where the other plants which represent a wide range of conditions would be poorly represented. It is important to note, however, that individual situations exist in which site-specific conditions make a cooling system retrofit extremely difficult. In such cases, the retrofit cost can be much greater than would be expected even for plants judged to be "Difficult" or "More Difficult". Other, although less extreme, examples are seen in Figure 3-1.

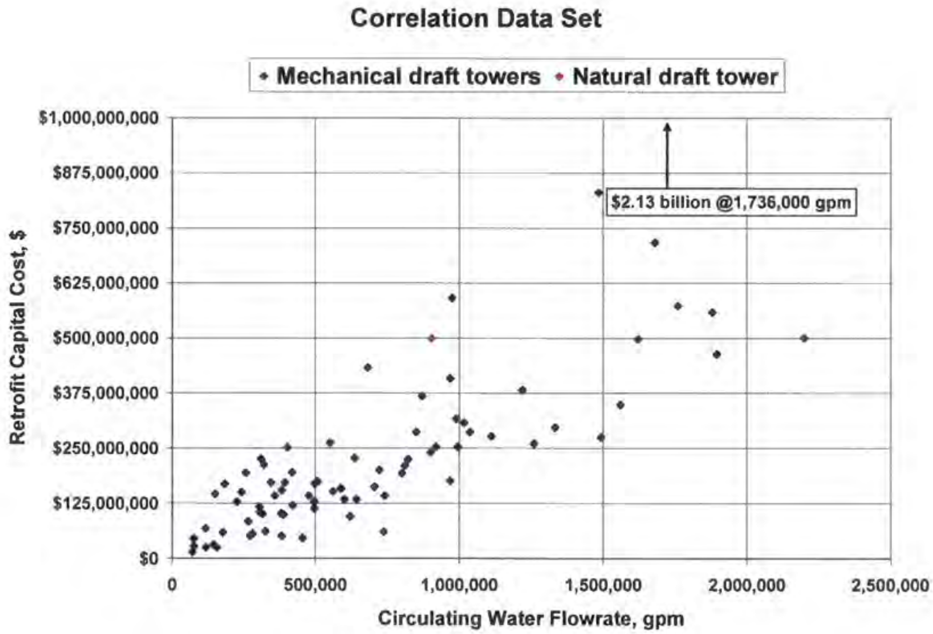

Figure 3-1: Plants with independent cost information

The 79 plants for which cost information is available break down into separate categories for nuclear and fossil plants and for fresh, brackish and saline source water and region of the country as tabulated in Tables 3-1a and 3-1b.

Table 3-1a: Distribution of Plant and Water Types for Plants Used in Correlations

Plants for Correlation Development			
Water Type	Fossil	Nuclear	Total
Fresh	37	4	41
Brackish	10	5	15
Saline	16	7	23
Total	63	16	79

Table 3-1b: Regional Distribution for Plants Used in Correlations

Regional Distribution			
Region	Number of plants		
	Fossil	Nuclear	Total
Mid-Atlantic	7	4	11
Midwest	16	2	18
North Central	1	2	3
Northeast	6	4	10
Pacific	12	2	14
South Central	2	0	2
Southeast	19	2	21
Total	63	16	79

Analysis of data

The 79 capital cost data points were compared and analyzed from several viewpoints prior to the establishment of the correlating equations for the "degree of difficulty" categories.

Choice of scaling factor

In order to establish cost ranges for an individual plant, it is necessary to select a scaling factor with which to modify costs from known plants as a function of the size of the cooling system. A number of obvious possibilities exist including plant capacity, cooling system heat load or cooling water flow rate.

The correlations would not be expected to be equivalent since neither the heat load nor the cooling water flow rate is necessarily well correlated to plant output given significant differences in plant type, plant efficiency and cooling system design. Figure 3-2, for example, shows the wide variation in the circulating water flow normalized with plant capacity (gpm/MW) for the 79 plants. While the range of circulating water flows per unit of plant capacity is similar for both fossil and nuclear plants, the average circulating water flow for nuclear plants is over 20% higher than for fossil plants.

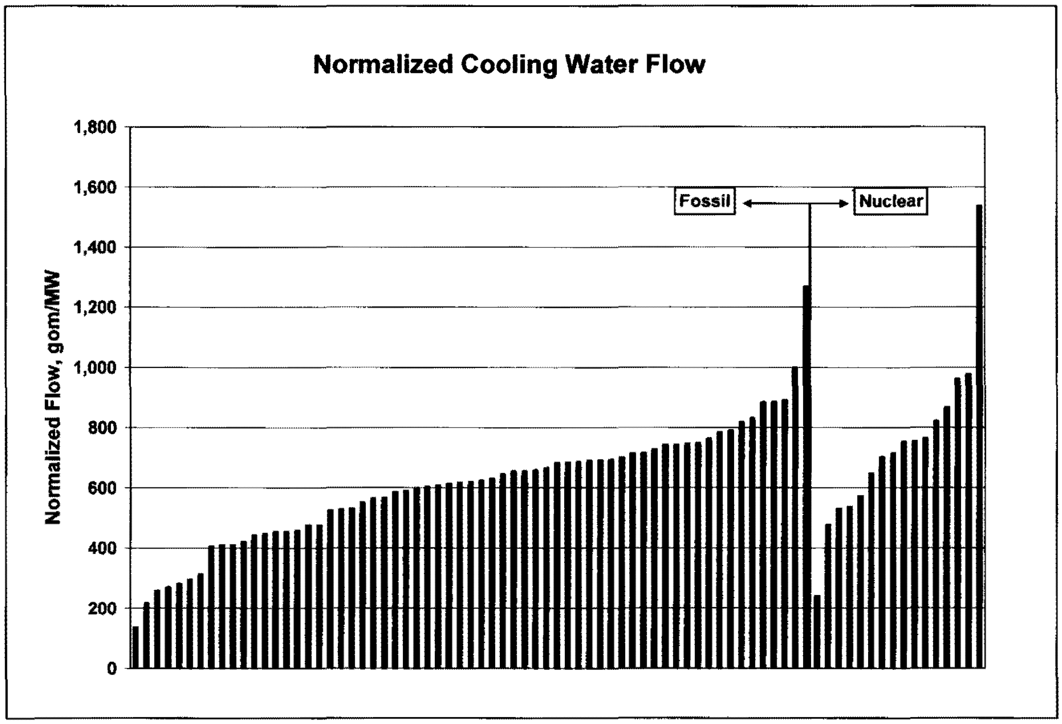

Figure 3-2
Normalized Cooling Water Flow Rate for Selected Plants

The circulating water flow was chosen to be the preferred scaling variable for several reasons:

1. Cooling system cost would be expected to be more closely related with water flow than with plant size (expressed in maximum output power in MW) given that the size of most of the important cooling system components (cooling tower, pumps, and piping) are primarily dependent on flow rate
2. Simple visual inspection of the data plotted against each of the three possibilities indicates a more consistent correlation with cooling water flow rate than with the others. Compare, for example, the plot of retrofit capital cost vs. plant capacity in Figure 3-3 with the plot against circulating water flow in Figure 3-4. While both exhibit considerable scatter, consistent with the site-specific nature of the projects, the cost range is greater and the outliers are more numerous in Figure 3-3. The correlation coefficient for a simple linear fit, while low in both cases, is significantly greater for the plot vs. circulating water flow ($R^2 = 0.67$) than it is for the plot vs. plant size ($R^2 = 0.34$).

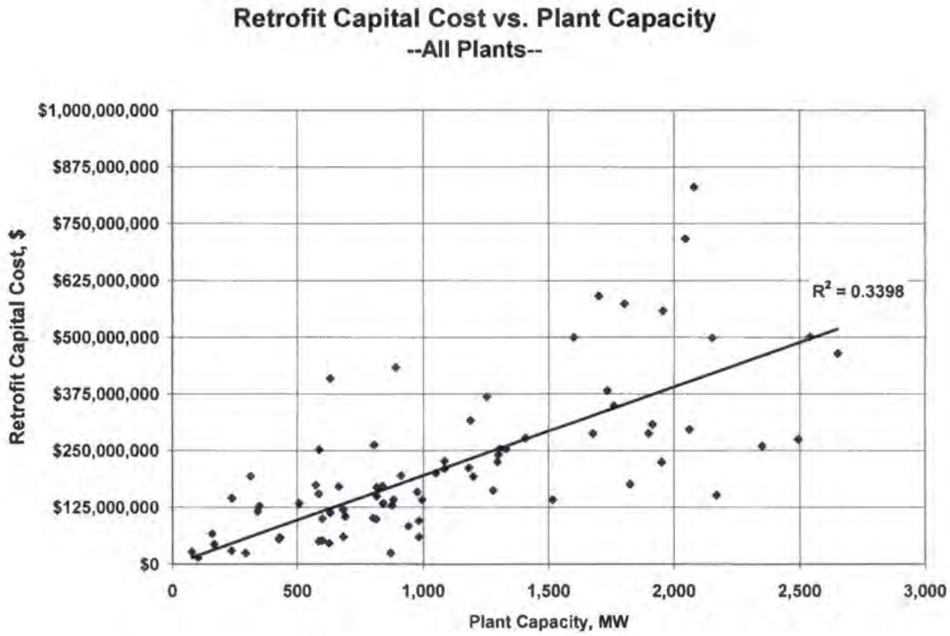

Figure 3-3: Retrofit Capital Cost vs. Plant Capacity

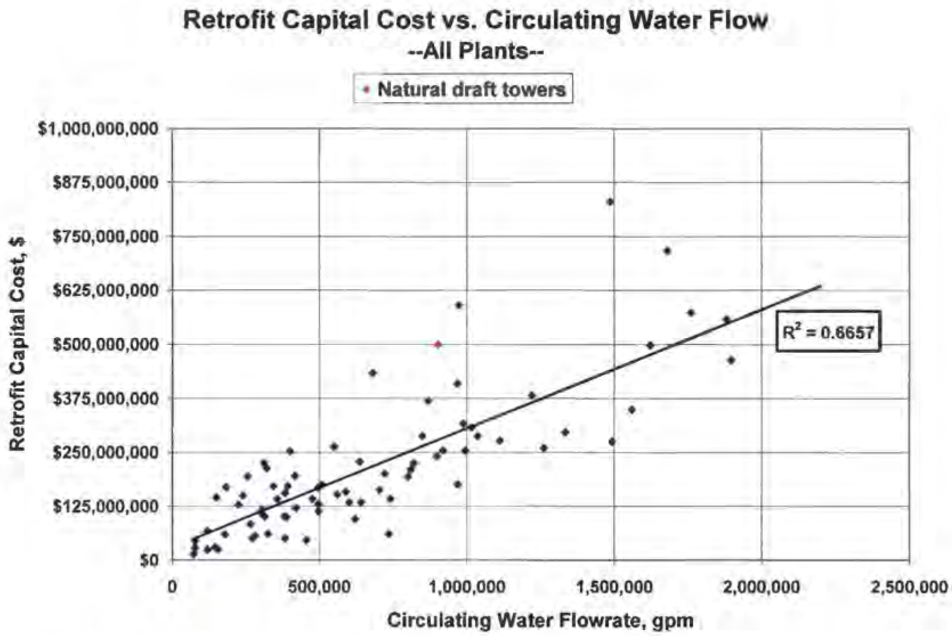

Figure 3-4: Retrofit Cost vs. Circulating Water Flow

Effect of other factors

The costs displayed in Figures 3-3 and 3-4 are from plants of different types, drawing make-up water from sources of different water quality and located in different regions of the country. Also, the estimated costs were obtained from different information sources. Before specifying simple linear cost correlations for each degree of difficulty, the data are examined in more detail to determine whether different correlations are required for different plant types, water sources and regions and whether data from all sources present a consistent picture.

Fuel types----fossil vs. nuclear

Figure 3-5 displays the retrofit capital cost data for all plants, differentiated as fossil or nuclear plants vs. circulating water flow. While there is considerable overlap in the two data sets, important differences exist between the costs for the two plant types. The nuclear plant costs exhibit more scatter than the fossil plants and represent a large fraction of the highest cost projects across the entire range of circulating water flow rates.

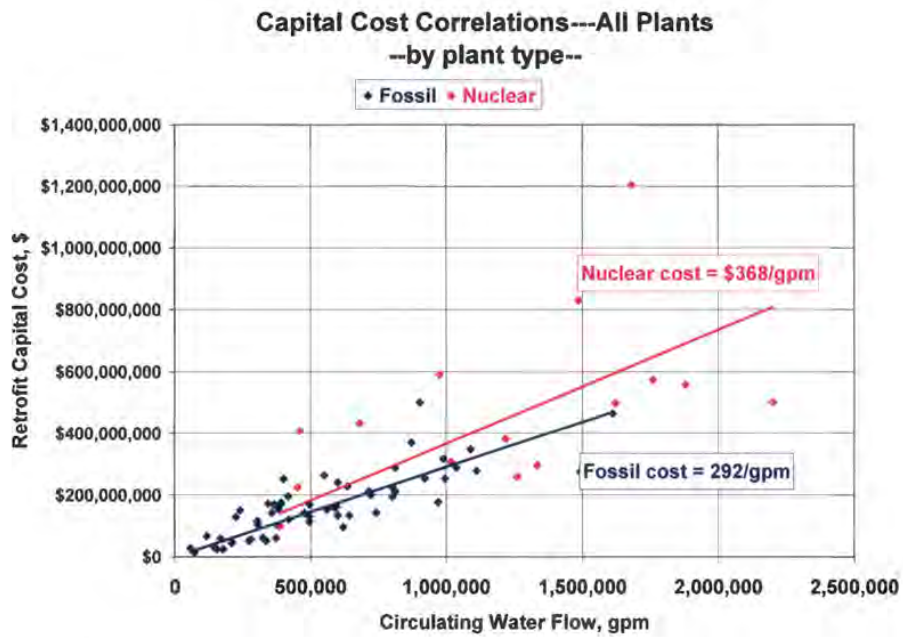

Figure 3-5
Retrofit Cost Data by Plant Type

This may be the result of several factors. The heat duty of the condenser cooling system for a given plant capacity (normalized condenser heat load in Btu/MWh) is greater for nuclear plants than for fossil plants for two reasons. First, nuclear plants operate at lower peak steam temperatures than do fossil plants and, as a result, have lower cycle efficiencies. Also, fossil plants reject a significant fraction of their waste heat through the stack whereas nuclear plants reject the entire waste heat load through the condenser. Therefore, in order to improve overall thermal efficiency, nuclear plants are typically designed with more efficient cooling systems and typically operate at higher circulating water flow rates on a gpm/MW basis. This generally requires, on the average, larger cooling system equipment for nuclear plants than for fossil plants of similar output.

The average cost of the nuclear power plants is approximately $368/gpm or about 26% higher than the $292/gpm average cost for fossil plants. Therefore, the correlations for fossil and nuclear plants were developed separately as subsequently discussed.

Fossil plant correlation development

Source water type

Figure 3-6 shows the cost vs. circulating flow data for fossil plants differentiated by source water: fresh, brackish and saline.

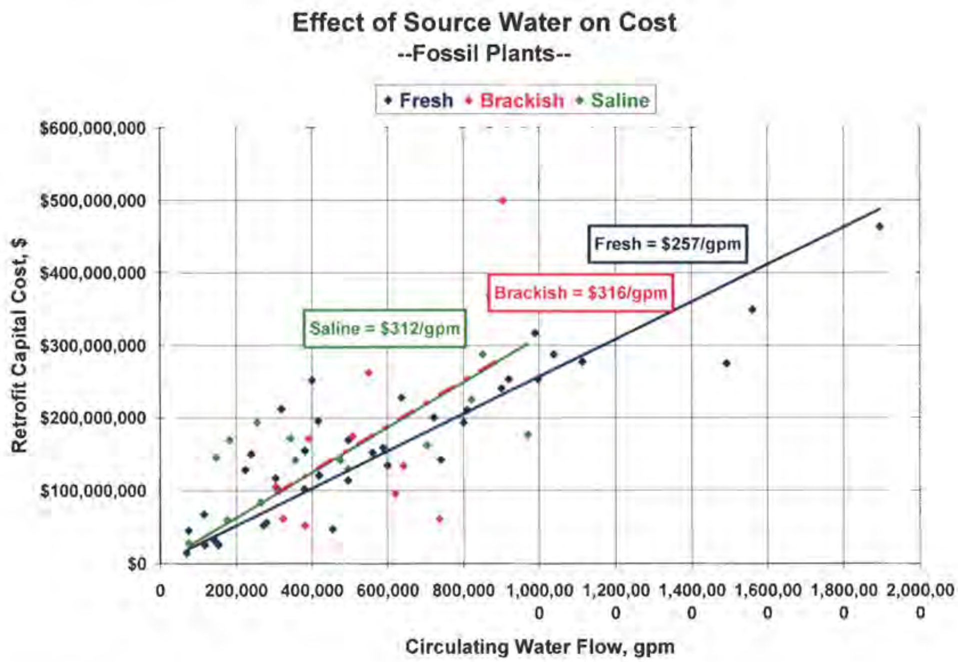

Figure 3-6
Effect of Source Water Type on Fossil Plant Retrofit Costs

Although cooling system components for saline water applications are typically more costly than those for freshwater applications (3-2), Figure 3-6 indicates that the average retrofit project cost difference between fresh and saline water plants is approximately 20%. While this is within the range of expected uncertainty of preliminary engineering estimates of major plant modification projects, it is also reasonably consistent with the results presented in the California Energy Commission report on salt water cooling towers (3-3). The difference in costs are attributable both to the requirement for a larger tower because of the lower evaporative cooling capability of salt water in comparison to fresh water and to the requirement for more expensive materials of construction to resist the corrosive nature of high salinity circulating water. The average brackish costs are approximately the same as the average of the saline water plant costs.

Given the relatively small sample size for any single source water data set, the decision was made not to develop separate correlations for each. However, in the final cost estimate, after the degree of difficulty has been determined and the appropriate correlation applied, the resulting cost estimate for fossil plants on saline or brackish water will be increased by 20%.

Regions of the country

The plants included in the correlating set came from several regions in the country. The regions and the included states are presented in Figure 3-7. The states were grouped in regions in an attempt to aggregate sites where the differences between the original source water temperature, which sets the performance of a once-through cooled system, and the ambient wet bulb temperature, which sets the performance of a closed-cycle wet cooling system, would be similar. While these differences are not likely to have an important effect on the capital costs of retrofit, they will be an important factor in determining the performance differences and the corresponding energy and capacity penalties as discussed in Chapter 7.

Figure 3-7: Geographical regions

The effect of location on the normalized capital cost of retrofit of fossil plants is shown in Figure 3-8.

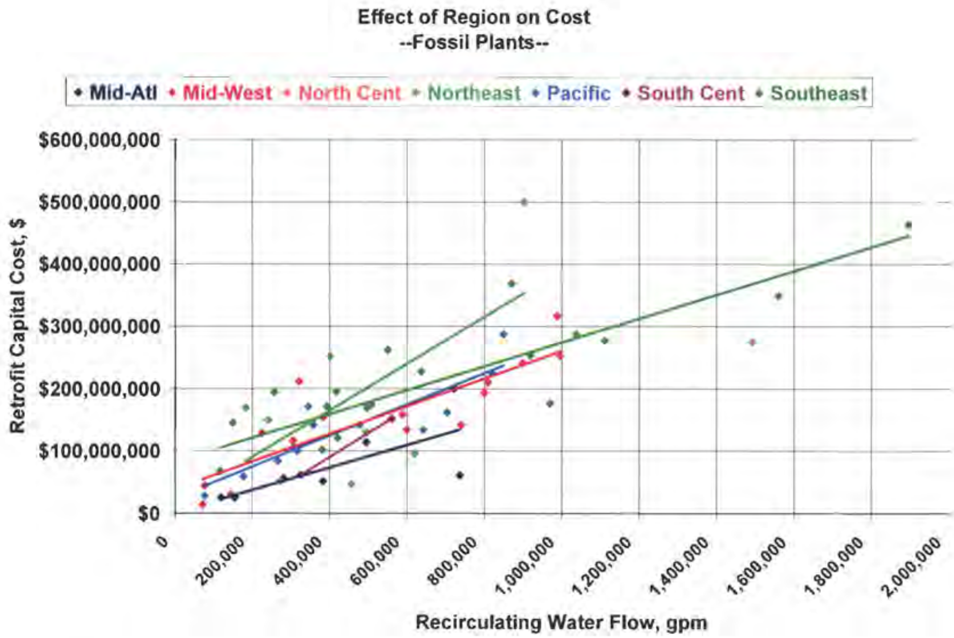

Figure 3-8
Effect of Location on Fossil Plant Retrofit Costs

There is no discernible systematic variation in the retrofit capital costs among the seven regions of the country displayed in Figure 3-8. The points at the high edge of the cluster are mainly points for coastal plants using salt water make-up in the Northeast, Southeast and Pacific regions. The freshwater plants from these same three regions are scattered more or less uniformly throughout the range. Therefore, the bias toward higher retrofit costs in these regions is attributed to a preponderance of high salinity source waters than to any other "region-specific" factor.

Data sources

The independent cost information, in the form of retrofit capital costs for a number of individual plants, was obtained from several sources including:

Category 1:	Individual utilities
Category 2:	California study sponsored by the California Ocean Protection Council (3-3)
Category 3:	EPRI 2002 utility survey and other sources (3-4)
Category 4:	EPRI 2008 utility survey

Category 1: The most complete, detailed information comes from individual utilities which made data available from 9 plants at which closed-cycle cooling retrofits were

either done or for which detailed, "bid-quality" studies were performed by independent architectural and engineering firms with power plant design and construction experience.

Included in this category are **9** plants (Fos 1, N321, F275, Fos 2, F483, N218, N233, F546, Fos 5) for which complete, detailed cost information is available for essentially every equipment, material, labor and indirect elements of the project cost. These points are the ones in which the greatest confidence can be placed. In addition, an internal comparison of the cost elements sheds light on which elements of a retrofit are the most variable and which are most likely to cause a particular project to be more or less "difficult". A listing of these plants and their relevant plant/site characteristics are given in Table 6-2. Detailed discussions of the cost information from each of these **7** plants and a comparison of their costs with the degree of difficulty ranges are contained in Appendix G. The results of the individual plant analyses are summarized in Chapter 6.

Category 2: A second category is a set of estimates for once-through cooled coastal plants in California. Although far less detailed than the Category 1 studies, these studies have the advantage that they were all performed by the same engineering firm ensuring a consistency of approach and careful attention to site-specific differences among nominally similar plants and sites.

Category 3: The largest category is made up of cost estimates assembled by EPRI in 2002 as part of a study conducted to develop comments for EPA's then current 316(b) rulemaking (3-4). The estimates came from a variety of sources including individual utilities, a set of cases from data assembled by DOE in the 1990's (3-5) and four individual case studies conducted by DOE's National Energy Technology Laboratory (NETL) for EPA (3-6). The date of the estimates and the level of detailed supporting information are highly variable.

Category 4: These estimates were recently obtained by EPRI as part of this current study through an industry-wide survey using the Cost Estimation Worksheet included in Appendix C. All are supported by studies conducted either by the utility's engineering department or an independent engineering firm. The depth and detail of the supporting information is less than for the Category 1 studies and similar to the Category 2 studies. The advantage is that these studies are all relatively recent and have current design, performance data and cost information.

It is interesting to note that these Category 4 estimates often lie at the high end of the range. This may result from several factors. First, most of these estimates are relatively recent and are not subject to the uncertainties associated with scaling up costs from previous years. Second, these estimates invariably contain a significant "Contingency" amounting typically to 30 to 35%. Finally, in light of the fact that these estimates may become firm obligations, more conservative assumptions may have been used.

Figure 3-9 displays the fossil plant retrofit cost estimates differentiated by these categories.

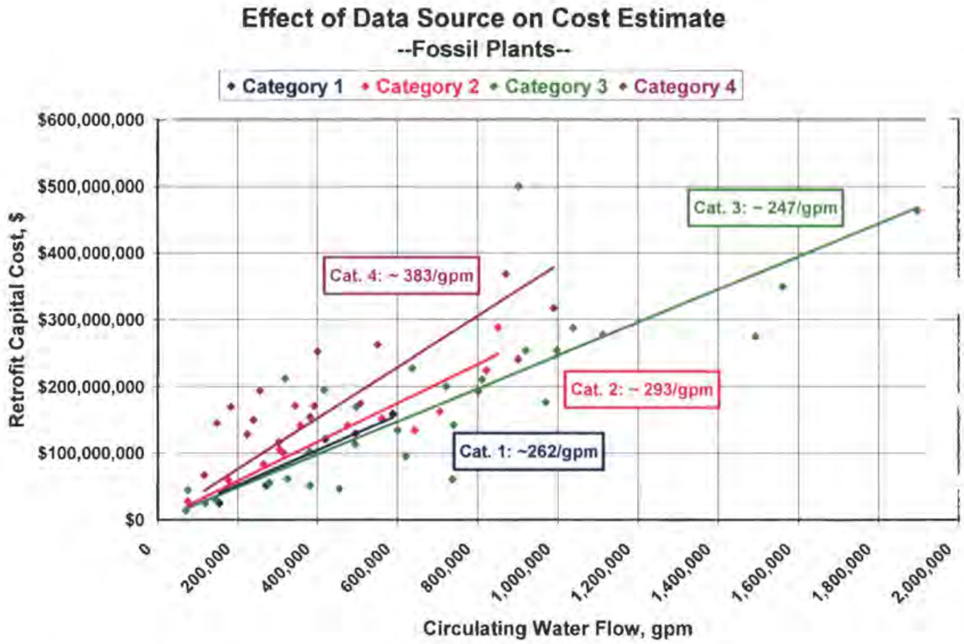

Figure 3-9: Fossil Plant Retrofit Costs by Data Source

The plot of the retrofit cost estimates in Figure 3-9 shows values from all categories spread across the entire cost range. Several observations are noteworthy.

1. In general, the points within each category show reasonable consistency. Category 3 exhibits the most scatter due in part to the greater number of points and to the fact they come from disparate sources as noted above.
2. Category 3 has the lowest average normalized cost. This may be due to the fact that, on average, the original estimates are older than those for the other three categories and the simple scaling relationships used to bring the costs up to 2009 equivalent costs may not capture all of the cost increases over many years.
3. Categories 1, 2 and 3 are in reasonable agreement with each other with a spread of less than +/-10%.
4. Category 4 is significantly higher than the others. This is likely due to several reasons. First, the estimates are the most recent. The estimates were conducted by experienced engineering firms with the objective of providing guidance to the plant owners in anticipation of a decision of whether or not to retrofit. This likely resulted in more detailed scrutiny and perhaps more conservative assumptions than was the case for the other categories.

5. Category 1 is perhaps surprisingly low since it represents both actual retrofits and detailed studies. However, the number of cases is small and, coincidentally, four of the six fossil plants in this category were judged to be "easy" retrofits for which comparatively low retrofit costs would be expected.
6. Finally, the number of cases in each category is small and some of the differences may be due simply to statistical aberrations. Given the good distribution of estimates from all categories across the range of circulating water flows and costs no distinctions will be made in the correlations on the basis of the source of the individual data points.

Fossil plant capital cost correlations

Figure 3-10 shows the costs for the fossil plants arranged in increasing order of the normalized retrofit costs ($/gpm).

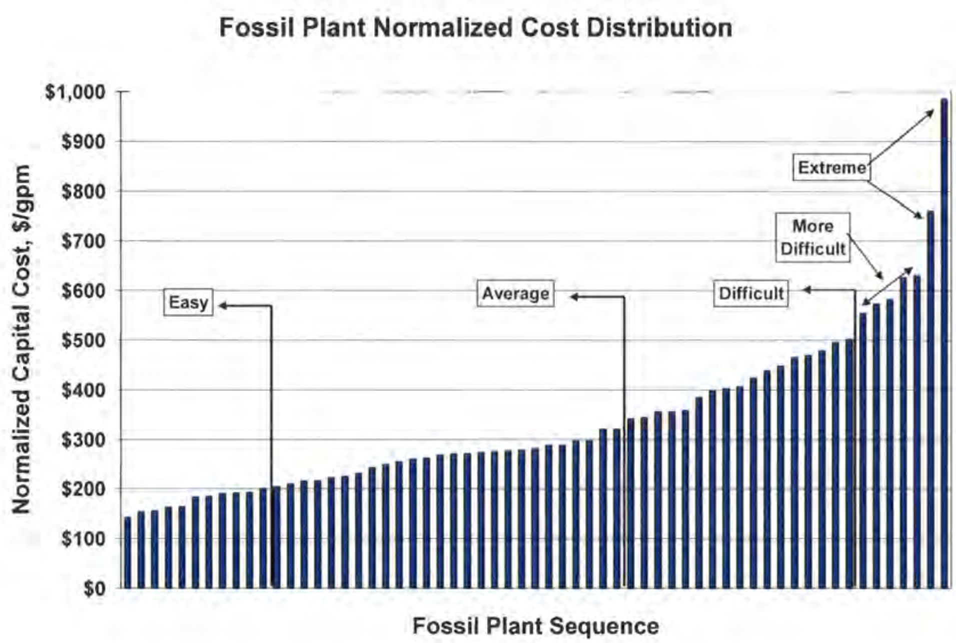

Figure 3-10: Categorization of Fossil Plant Costs by Degree of Difficulty

Figure 3-11 displays the fossil plant data with the correlating lines superimposed on the plot. The division between the categories is somewhat arbitrary. There are no distinct "break points" at most of the lines of demarcation, but the average cost estimated for each of the three categories are distinctly different, and the variation from the average within each group is modest. In the interest of keeping the number of categories to a minimum in order to get a reasonable sample size in each group, the choice of "round number" costs as the dividing lines was made. Different choices as to the groupings would not be expected to have any important effect on the eventual national cost totals.

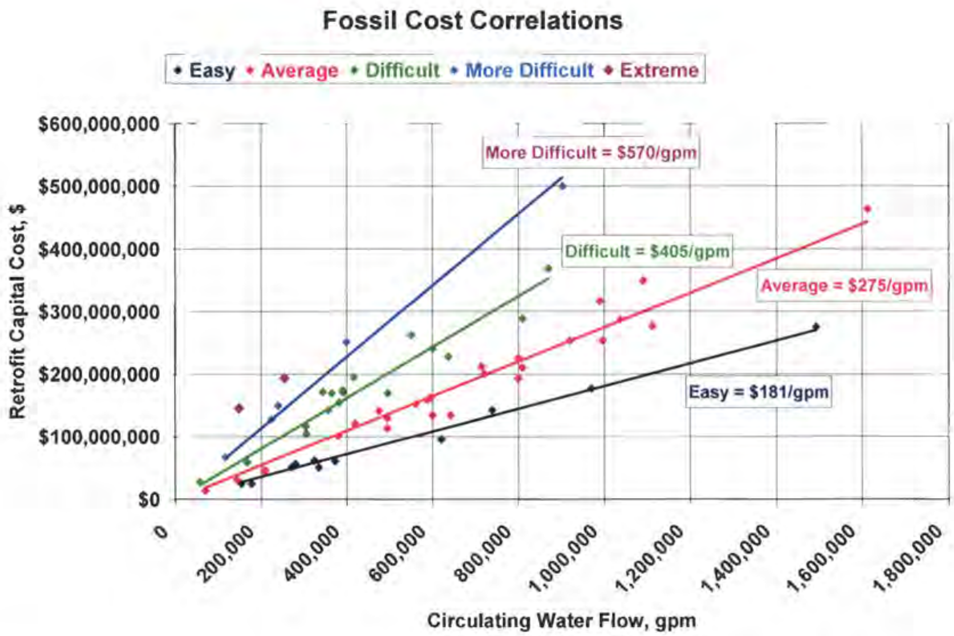

Figure 3-11:
Fossil Plant Retrofit Capital Cost Correlations

The coefficients in the linear correlating equations for the four degrees of difficulty for fossil plants are:

Easy:	**$181/gpm**
Average:	**$275/gpm**
Difficult:	**$405/gpm**
More difficult:	**$570/gpm**

Nuclear plant correlation development

As seen in Figure 3-5, the cost estimates for nuclear plants are far fewer in number than those for fossil plants, but they exhibit greater variability. Before developing correlations for nuclear retrofits, the effects of source water quality and data source are examined.

Nuclear plants—effect of source water type

Figure 3-12 shows the nuclear plant retrofit costs differentiated by source cooling water type. Although the small number of plants and the significant amount of scatter in each category makes comparisons difficult, the average of the costs for the saline plant retrofits is about 15% higher than that for the fresh water nuclear plants. This is reasonably consistent with the 20% difference observed in the fossil plant data. However, unlike the fossil plants where the saline and brackish water plant costs agreed well, the brackish water plant costs for the nuclear plants average about 20% less than the fresh water plants.

Since the characteristics of brackish water are nominally intermediate between saline and fresh water characteristics, there is no immediately apparent reason for this difference. It is, therefore, assumed that the difference is a statistical aberration due to the small sample size or that these plants are, on average, slightly less difficult retrofits than the bulk of the nuclear sites for reasons having little or nothing to do with the quality of the make-up water. Therefore, no differentiation among source water types will be made for nuclear plants and no adjustment is made for the brackish plants.

There is a consistent result that retrofit costs for plants with saline water make-up are higher than for plants on fresh water make-up for the same cooling system circulating water flow rate. The difference, however, of approximately 15 to 20% is felt to be within the level of precision of the correlation given the paucity of data points and the scatter among them. Therefore, the cost range for nuclear plant retrofits will be established without reference to source water type. However, as was discussed in the section on fossil plants, the determination of the degree of difficulty will be made on all the other factors and then an upward adjustment of 20% will be made for plants with saline make-up.

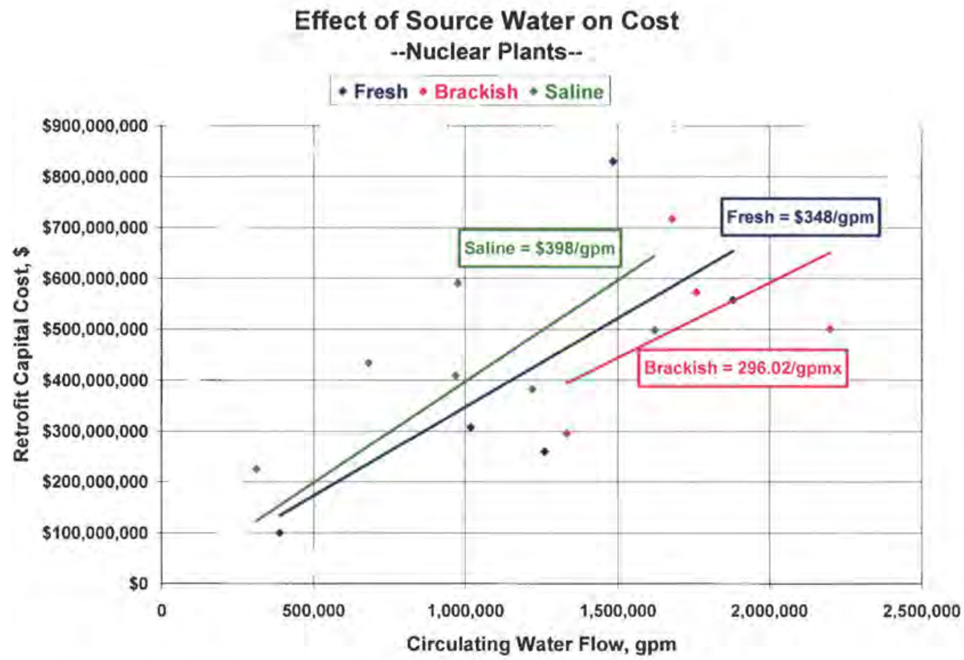

Figure 3-12
Effect of Source Water Type on Nuclear Plant Retrofit Costs

Regions of the country

As was the case for the fossil plants, the nuclear plants included in the correlating set came from several regions in the country. The effect of location on normalized capital cost of retrofit of nuclear plants is shown in Figure 3-13.

While there is considerable scatter, there is no discernible separation by region and no differentiation, therefore, is made among the nuclear plants on a regional basis. As was the case for the fossil plants (Figure 3-8), the highest points are associated with oceanside plants with seawater make-up and not with any other region-specific factors.

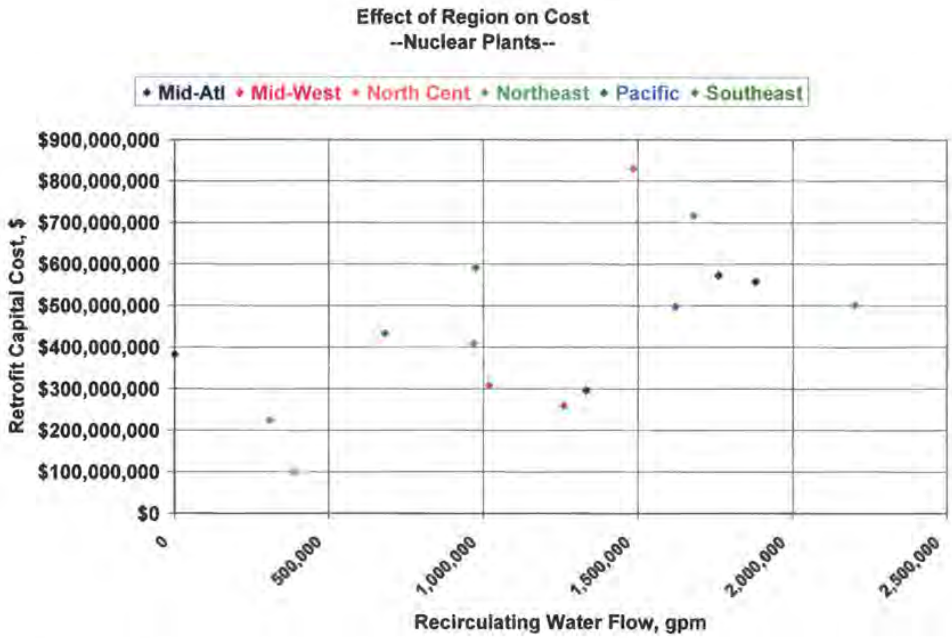

Figure 3-13: Effect of Location Nuclear Plant Retrofit Costs

Nuclear plants—effect of data source

Figure 3-14 presents the nuclear plant retrofit costs differentiated by the source of the data. The categories are the same as those described for fossil plant cost estimates in the previous section. Only Category 3 contains more than 2 plants. Therefore, the statistical uncertainty in the linear fits for Categories 1, 2 and 4 is high, and no conclusions were drawn from this comparison of sources. It is simply assumed that the high cost points represent plants of a more difficult retrofit situation and will be included in the nuclear correlations displayed in Figure 3-16. In the case of nuclear plants, the source of cost estimates makes no difference to the magnitude of the estimated costs.

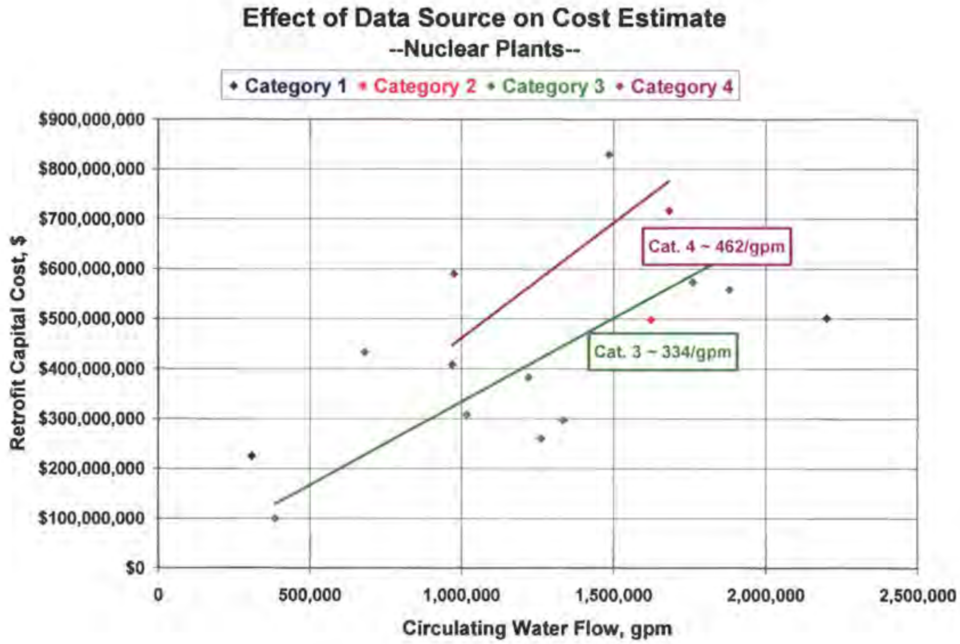

Figure 3-14
Effect of Data Source on Nuclear Plant Retrofit Costs

Nuclear plant correlation development

The small number and large variability of nuclear plant cost estimates makes it impossible to create precise estimates of the average cost/gpm for the four distinct categories (Easy, Average, Difficult, More difficult) as was done for the fossil plants. The approach taken was to rank the nuclear plant costs estimates by normalized cost as shown in Figure 3-15. The costs for plants 1 through 9 were identified as "Less Difficult" and plants 10 through 15, as "More Difficult." Point 16 (N-321) was referred to earlier as a significant outlier and is not included in the development of the correlating equation. While the selection of a line of demarcation is a matter of judgment, a slight breakpoint does appear between plants 6 and 7. The separation of the estimates into these two categories, along with the selected correlation lines, is shown in Figure 3-16.

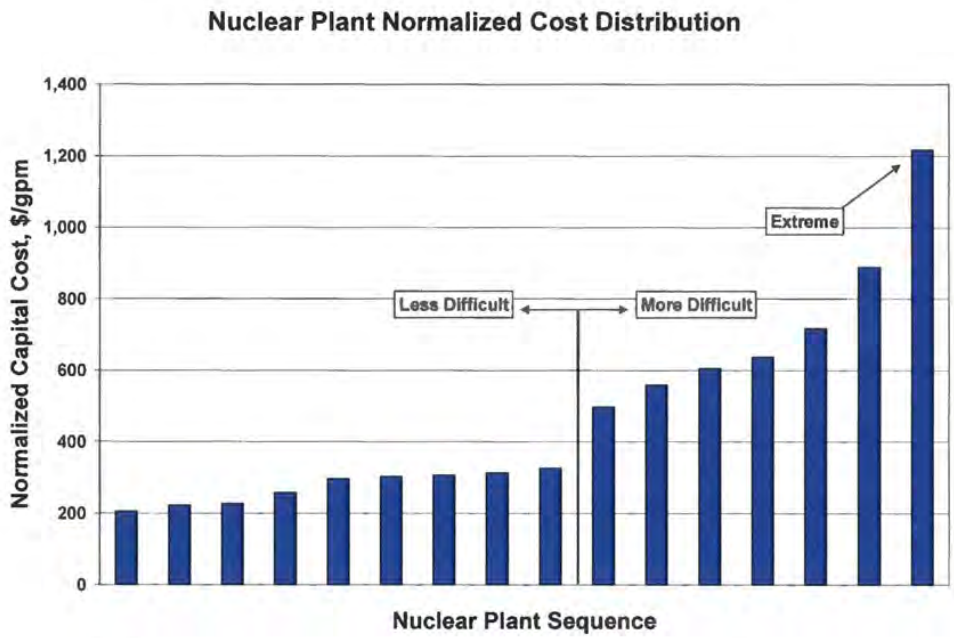

Figure 3-15: Normalized Cost Estimates for Nuclear Plant Retrofits

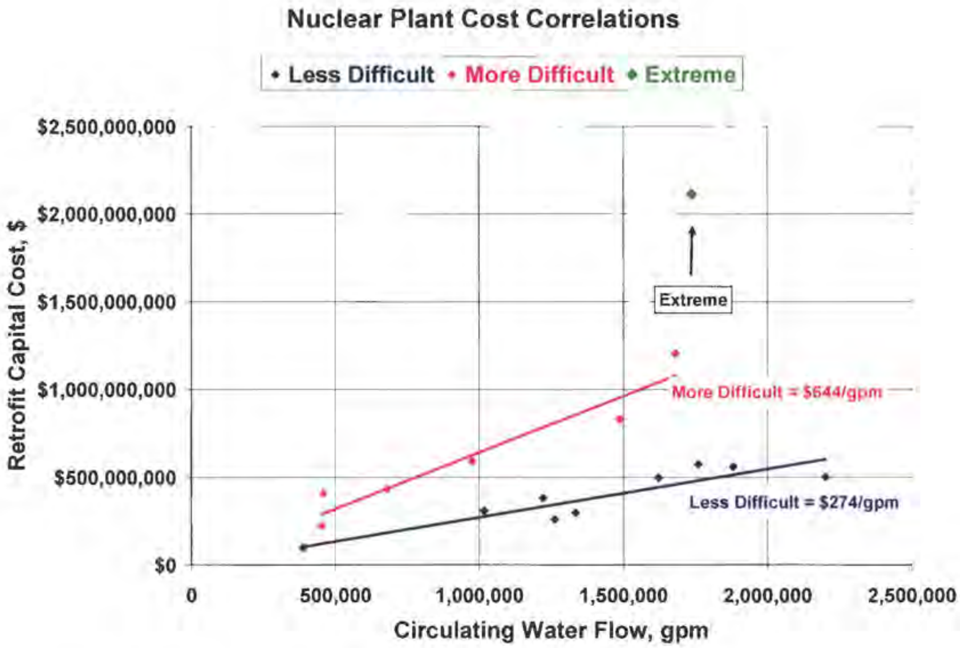

Figure 3-16: Correlations for Nuclear Plant Capital Cost Estimates

The coefficients in the linear correlating equations for nuclear plant retrofits are:

"Less difficult":	**$274/gpm**
"More difficult":	**$644/gpm**

<u>Observations on correlating equations</u>

Examination of Figures 3-11 and 3-16 shows that the correlating equations are simply linear fits to clusters of data that represent the range of cost estimates and are selected to represents retrofits of varying degrees of difficulty. It is clear that they do not represent "bounds" on the costs of individual retrofits. That is, there are cases where the costs are less than what the "Easy" correlation would give and cases which are higher, sometimes significantly so, than the cost that would be obtained from the application of the "Difficult" or "More Difficult" correlation. Therefore, they are in no sense a "prediction" of the cost for any individual plant but rather an indication of the likely range of cost to be expected for a plant of a given circulating water flow rate.

Finally, the assertion that these cost ranges are attributable to site-specific features which influence the "degree of difficulty" of an individual retrofit project at a given plant is a plausible and useful, but unproved, assertion. The usefulness of this hypothesis will be illustrated through the examination of a group of individual plants for which site-specific information has been obtained (Chapters 4 and 5) and the assignment of a degree of difficulty to each plant. Where possible, the resulting cost estimates will be compared to independently obtained cost estimates as a partial validation of the methodology (Chapter 6).

Chapter 3 References

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3.3 California's Coastal Power Plants: Alternative Cooling System Analysis, TetraTech, Inc. February, 2008 (Available on California Ocean Protection Council Website at http://resources.ca.gov/copc/)

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3.5 Veil, John A., Impact on the Steam Electric Power Industry of Deleting Section 316(a) of the Clean Water Act, ANL/EAI8-4, Argonne National Laboratory, U. S. Department of Energy, January, 1993.

3.6 An Investigation of Site-specific Considerations for Retrofitting Recirculating Cooling Towers at Existing Power Plants---A Four-Site Case Study, Parsons Infrastructure and Technology Group, Inc. and DOE National Technology Laboratory, May, 2002.

4

ESTABLISHMENT OF DEGREE OF DIFFICULTY

Site-specific information

In order to develop an estimate of the retrofit cost for a specific plant, it is necessary to estimate the degree of difficulty of a retrofitting the cooling system at the site in order to determine where in the range of costs developed in Chapter 3, the plant would be expected to fall. Nationwide, there are approximately 444 plants (404 fossil; 40 nuclear) classified as Phase II facilities (Appendix A).

As part of this study, site-specific information on the generating units, the cooling systems and the site characteristics was requested from the Phase II facilities. This was accomplished by distributing a cost estimation worksheet to all the member companies of five major utility organizations including the Utility Water Act Group (UWAG), the Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) as well as EPRI itself.

The information solicited covered the following subject areas:

Items related to the degree of difficulty and capital cost determination include:

- General descriptive information the plant and for each unit
  (location, capacity, water flows, source water type, fuel, year on-line, etc.)
- Site characteristics
  (plot plan, boundaries, elevation profiles, structures, underground utilities, geology)
- Neighborhood characteristics
  (general character [rural, urban, suburban, industrial, commercial], nearby residential areas, schools, churches, roads, airports, etc.)
- Alternate water sources
  (source type, distance from source to plant, applicable regulations on use)

Additional items for estimating additional power costs and efficiency/capacity penalties include:

- Site meteorological data
  (source water temperatures, dry and wet bulb temperatures)
- Cooling system design characteristics
  (condenser specifications, turbine heat rate curves)
- Unit operating profiles
  (load scheduling, outage times)

– Plant economic factors
  (fuel costs, power price)

On the basis of information provided, the questionnaire spreadsheets automatically calculated the following quantities:

– Probable range of retrofit capital costs
  (Easy, Average, Difficult and More Difficult for fossil plants; Less Difficult and More Difficult for nuclear plants)

– Cooling tower size
  (Number of cells, footprint dimensions, height)

– Additional operating power costs
  (Fan and pump power)

– Capital and annualized retrofit cost summary

Responses were received from about 185 plants. The information obtained was intended to permit the evaluation of the factors most relevant to establishing the site-specific degree of difficulty that were introduced in Chapter 2 in Table 2-1.

These factors are discussed in more detail below.

Important Plant /Site Characteristics

Item 1--Tower location: Plant sites vary widely in the amount of open space available within existing site boundaries, and cooling towers require a large amount of space. A recent retrofit at a 550 MW coal-fired plant in the southeastern U.S. required the installation of a 40-cell tower with a footprint of approximately 1,000 by 100 feet. This tower was erected in a back-to-back arrangement. If plume abatement had been required, an in-line arrangement would have been necessary, requiring a much longer open area for a single tower or a much wider one if two separate towers had been chosen. Additional requirements, such as the need to align a tower lengthwise with the prevailing winds in order to avoid recirculation, can further limit the available options for siting the towers. Towers can often not be sited near switchgear if there is concern that drift deposition may coat the surface of insulators with conductive salts and lead to a breakdown of the insulating capability.

If no space is available within existing boundaries, the only remaining option would be to purchase adjoining land, if available, at indeterminate cost. The lack of space on the existing site will be considered to make a closed-cycle retrofit infeasible.

Item 2--Separation distance: In some instances, the only available location for a cooling tower is far removed from the turbine building and condenser. While for new plant construction most towers are placed within a few hundred feet of the turbine building, in retrofits, separation distances of 1,000 feet or more may be required. As will be discussed in Items 3 and 4, the increased separation distance, in addition to increasing the material and labor cost of installing the circulating water lines and the required pumping power, also increases the likelihood of encountering unfavorable or confounding geologic conditions or additional interferences (e.g., pipes and other interferences as discussed in item 4 below) which can add greatly to the difficulty of the project.

Item 3--Unusual site preparation requirements: Site problems which are known to significantly increase retrofit costs are:

- The presence of saturated unstable soils for which extensive damming, drainage or the installation of pilings are required in order to provide a stable platform for the cooling tower
- The presence of bedrock which requires costly drilling or blasting in order to install underground circulating water lines
- The presence of contaminated soils with associated costly handling and disposal requirements
- The presence of known archeological artifacts or threatened and endangered species protection requirements.

Item 4--Underground interferences: This is a common cause of difficulty in retrofit projects. Existing plant sites are often underlain with numerous runs of piping, electrical lines, power buses, storage tanks and communication lines. In a recent project in northern California, the routing of new circulating water lines across the existing plant site encountered nearly 200 separate interferences over a distance of about 1,500 feet, increasing the installation cost of the lines by nearly a factor of five.

Item 5--Condenser/tunnel reinforcement: There may or may not be a need for condenser and tunnel reinforcement depending on how the cooling tower circulation loop is tied into the existing once-through cooling loop. Two general approaches can be taken;

1. In some cases, the existing condenser and circulating water pumps are left essentially undisturbed. The circulating water is pumped through the condenser as before, but the discharge line, instead of returning to the source waterbody, is re-routed to a sump. A new set of circulating water pumps is installed. These pumps draw from the new sump and pump to the hot water distribution deck on top of the cooling tower. Cold water from the tower basin then returns by gravity to the existing inlet bay. This may require grading the site for the tower to provide sufficient elevation to enable the gravity return. In this case, the condenser and the existing water tunnels see the same flows and pressures as before, and no modification is required. However, the location of a sump of adequate size can be a problem and a costly part of the installation at some sites. In a case where it may be impossible to locate a tower at an elevation higher than the condenser, it would be necessary to pump the cold water back to the condenser. This may require an additional set of pumps.
2. An alternative approach is to replace the existing circulating water pumps with pumps of higher head, which pump the water through the condenser and then to the top of the tower. This can double, or more than double, the pressure in the condenser waterboxes and the existing inlet and discharge tunnels. In this case, condenser waterbox and perhaps tube sheet stiffening will likely be required and tunnel reinforcement, sometimes by lining the existing tunnels with steel pipe, may be necessary.

Item 6—Plume abatement: The discharge of warm, saturated air from the cooling tower can produce a large visible plume when it mixes with cooler ambient air under some atmospheric conditions. This plume can be unacceptable in some situations such as, for example, if it were to create visibility problems on a nearby highway or for an airport. Even in the absence of safety considerations, it may be unacceptable on aesthetic grounds to nearby residential communities, recreational areas or scenic viewsheds. In such cases, plume abatement may be required in order to obtain permits for the tower. While plume abatement designs exist, they are nearly three times the cost of a conventional tower (4-1) and, as noted above, require in-line tower arrangements which can further complicate the siting of a tower on a congested site.

Item 7---Drift: In addition to visible plumes, cooling towers continuously emit a small amount of liquid water entrained in the discharge air as very small droplets, known as drift. While state-of-the-art, high performance drift eliminators can reduce the drift rate to a very low level (<0.0005% of the circulating water flow), it cannot be eliminated entirely. Depending on the quality of the cooling tower make-up water and the cycles of concentration at which the tower is operated, the drift will contain varying amounts of dissolved solids. The drift salinity will be the highest from towers using make-up water of high salinity from oceans, estuaries and tidal rivers.

The deposition of drift on the plant site can lead to increased maintenance requirements if it falls on structures, vehicles or switchyard equipment. Additionally, the presence of "sensitive receptors" (e.g., hospitals, senior citizen facilities, sensitive crops, schools, historic areas, dense population areas) close to the site boundary may lead to serious objections to the permitting of a tower at the site, and no technological solution exists to mitigate the problem. In such cases, a retrofit to closed-cycle cooling with wet cooling towers would likely be deemed infeasible.

Item 8—Noise reduction: Mechanical draft cooling towers produce continuous noise both from the fans and from the water falling through the fill and into the basin. Typical sound levels are about 70 dBa at a distance of 50 feet from the tower. This is not normally a problem within the plant boundaries. However, if the tower is located near the plant boundary, there may be sensitive receptors close to the plant, such as residences, places of worship, hospitals, senior citizen facilities and schools. There also may be noise ordinances that require meeting specified noise limits within a certain distance from the property boundary. In this case, sound barriers or inlet/outlet sound attenuation equipment may be used, but at a substantial increase in cost. (4-2)

Item 9--Alternate water sources: Under some circumstances, the source of cooling water which had been used for once-through cooling may be undesirable for use as make up to a closed-cycle cooling system. One example would be the use of seawater for once-through cooling of coastal plants, where high salinity drift or fine salt particles (potentially PM10) would be created by a cooling tower operating with seawater make-up. An option in this case might be the use of alternate sources of cooling water such as, for example, waste water from neighboring municipal water treatment plants, agricultural irrigation drainage or produced water from oil and gas or mining operations. This choice usually requires the installation of long-distance supply pipelines from the alternate source water location to the plant, and possible treatment prior to use of the water to reduce corrosion, fouling or scaling problems or to address issues of wastewater disposal. These approaches can add considerably to the difficulty and hence cost of the retrofit project.

Item 10--Related modifications to balance of plant: Many plants use the same intake facilities that are used for the once-through cooling system for intake to their auxiliary cooling systems and other water needs. To the extent that these systems have been sized on the basis of expected cold water temperatures, the systems may not operate satisfactorily on cold water return from a cooling tower during some portions of the year. This may require either a redesign of the plant inlet water facilities or the redesign and refurbishment of the auxiliary cooling water system to accommodate the altered operating conditions on closed-cycle cooling.

In some plants, cooled condensate from the primary steam cycle has been used for generator cooling. Condensate leaving the condenser is passed through a heat exchanger cooled with cold-side cooling water and thence to the generator cooling passages. The closed-cycle retrofit will lead to higher condensing temperatures during summer months, and the condensate cooler may not be of sufficient size to provide low enough temperature water to the generator. This would require additional modifications to this auxiliary cooling loop of unknown cost and complexity.

Item 11---Re-optimization of the cooling system: An important consideration in cooling system retrofits is whether the entire cooling system should be re-optimized to account for fundamental performance differences between once-through and closed-cycle cooling. In brief, closed-cycle cooling systems optimize at a lower flow rate and a higher cooling water temperature rise than do once-through cooling systems. Therefore, simply inserting a cooling tower into an existing once-through cooling loop results in a less effective and more costly cooling tower and higher operating power requirements than would be the case for a properly optimized closed-cycle cooling system. Re-optimization would normally significantly reduce the circulating water flow rate which, in turn, would require major modifications to the existing condenser, circulating water pumps and piping. Re-optimization should be considered as part of a retrofit for plants with high capacity factors and long remaining life, as is normally the case for nuclear plants. This subject and the effect on retrofit costs will be discussed in greater detail in Chapter 5.

Additional issues

Item 1—Outage time: While the cost resulting from a prolonged outage is not a capital cost, it is, nonetheless, an important cost due to the loss of revenue from these units and is related to the extent and complexity of the retrofit. Although much of the installation of the cooling tower and the circulating water piping typically can be done while the plant is on-line and operating on its existing cooling water system, the final tie-in of the new circulating water lines to the condenser inlet and discharge tunnels requires that the plant be shut down. An additional factor may be a need to relocate essential structures and plant facilities in order to make space for the tower. In some instances, the plant would be inoperable while those facilities were being changed over. This is particularly important if the cooling system is to be re-optimized, since this normally requires extensive modification or removal and replacement of the condenser and the associated piping.

A thorough investigation of these factors and estimates of the time required to accomplish them at various plants are beyond the scope of this study. However, it is noted that the outage durations at some moderate size fossil plants have been from 2 to 3 months. Estimates of the outage duration at some large nuclear plants have been as long as one to two years (due, in part, to the more likely need to re-optimize cooling systems at nuclear plants as discussed earlier (4-3, 4-4).

Item 2—Permitting: The installation of cooling towers at existing plants will require the application for and granting of new permits related to aqueous discharge of tower blowdown, drift emissions, noise and visual impact in most instances. The time and effort involved in these permitting procedures can be expected to add a significant amount to both the cost and the duration of the retrofit effort, but no information is available to estimate their magnitude. The inability to obtain such permits can prevent a retrofit project from proceeding.

Item 3:---Requirements specific to nuclear facilities: Important modifications to nuclear facilities are subject to extensive review and approval by the Nuclear Regulatory Commission (NRC). This includes not only design and operating safety considerations but also issues related to plant security. For example, the secured perimeter of the plant may need to be extended to include the location of the cooling towers if they must be sited outside the existing secured perimeter. This may require the installation of additional monitoring equipment and the possible requirement for more security staff. All of these issues would require obtaining the necessary approvals from the NRC before proceeding. As in the case of the local permitting requirements discussed above, the cost and effort of obtaining this approval is indeterminate but can be expected to add important difficulty and associated cost to the effort.

Site-specific analyses

Information was received from 185 plants, listed in Appendix D. Tables 4-1a through 4.1d show the distribution of both the entire family of Phase II facilities and the 185 facilities for which cost estimation worksheets were returned among several categories of plant size, fuel type, source water, and location by region. The tables confirm that the set of worksheets obtained are a reasonable representation of the complete family of Phase II facilities.

Table 4-1a: Worksheet distribution by plant type vs. Phase II population

Plant Type Distribution				
Plant Type	Phase II Facilities		Spreadsheets	
	Number	%	Number	%
Fossil	406	91.0%	166	89.7%
Nuclear	40	9.0%	19	10.3%
Total	446	100.0%	185	100.0%

Table 4-1b: Worksheet Distribution by source water vs. Phase II population

Source Water Distribution								
Plant Size, MW	Fossil				Nuclear			
	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
Great Lakes	43	10.6%	17	10.2%	6	15.0%	5	26.3%
Lakes and Reservoirs	79	19.5%	25	15.1%	12	30.0%	2	10.5%
O/E/TR*	101	24.9%	53	31.9%	13	32.5%	11	57.9%
Rivers	183	45.1%	71	42.8%	9	22.5%	1	5.3%
Total	406	100.0%	166	100.0%	40	100.0%	19	100.0%

Table 4-1c: Worksheet distribution by water quality vs. Phase II population

Water Quality Distribution								
Source Water	Fossil				Nuclear			
	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
Fresh	305	75.1%	113	68.1%	27	67.5%	8	42.1%
Brackish	76	18.7%	36	21.7%	5	12.5%	6	31.6%
Saline	25	6.2%	17	10.2%	8	20.0%	5	26.3%
Total	406	100.0%	166	100.0%	40	100.0%	19	100.0%

Table 4-1d: Worksheet distribution by plant size vs. Phase II population

Plant Size Distribution								
Plant Size, MW	Fossil				Nuclear			
	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
< 200	101	24.9%	24	14.5%	0	0.0%	0	0.0%
200 - 500	101	24.9%	39	23.5%	1	2.5%	0	0.0%
500 - 1,000	110	27.1%	55	33.1%	11	27.5%	4	21.1%
> 1,000	94	23.2%	48	28.9%	28	70.0%	15	78.9%
Total	406	100.0%	166	100.0%	40	100.0%	19	100.0%

Table 4-1e: Worksheet distribution by region vs. Phase II population

Regional Distribution								
Region	Fossil				Nuclear			
	Phase II Facilities		Spreadsheets		Phase II Facilities		Spreadsheets	
	Number	%	Number	%	Number	%	Number	%
Mid-Atlantic	35	8.6%	21	12.7%	10	25.0%	6	31.6%
Midwest	87	21.4%	34	20.5%	4	10.0%	1	5.3%
North Central	69	17.0%	17	10.2%	7	17.5%	3	15.8%
Northeast	66	16.3%	20	12.0%	9	22.5%	4	21.1%
Northern Plains	4	1.0%	1	0.6%	0	0.0%	0	0.0%
Pacific	22	5.4%	20	12.0%	2	5.0%	2	10.5%
South Central	52	12.8%	13	7.8%	2	5.0%	1	5.3%
Southeast	70	17.2%	40	24.1%	6	15.0%	2	10.5%
Southwest	1	0.2%	0	0.0%	0	0.0%	0	0.0%
Total	406	100.0%	166	100.0%	40	100.0%	19	100.0%

Of the 185 plants for which cost worksheets were submitted approximately half provided information of sufficient completeness and detail to allow an assessment of the factors affecting the difficulty of retrofit. The remainder provided more limited information which made the level of confidence in the determination of the difficulty of retrofit lower. In order to develop what was considered to be a representative sample of "evaluated plants", 125 plants with the most complete information were chosen for site-specific analysis. The distribution of these plants among the same categories noted above is presented in Tables 4-2a through 4-2d.

Table 4-2a: Distribution of analyzed plants by plant type vs. Phase II population

Distribution of Write-ups				
Plant Type	Phase II Facilities		Write-ups	
	Number	%	Number	%
Fossil	406	91.0%	115	92.0%
Nuclear	40	9.0%	10	8.0%
Total	446	100.0%	125	100.0%

Table 4-2b: Distribution of analyzed plants by source water vs. Phase II population

Source Water Distribution of Write-ups								
Source Water	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
Great Lakes	43	10.6%	16	13.9%	6	15.0%	3	30.0%
Lakes and Reservoirs	79	19.5%	18	15.7%	12	30.0%	2	20.0%
O/E/TR*	101	24.9%	32	27.8%	13	32.5%	4	40.0%
Rivers	183	45.1%	49	42.6%	9	22.5%	1	10.0%
Total	406	100.0%	115	100.0%	40	100.0%	10	100.0%

*Oceans, estuaries and tidal rivers

Table 4-2c: Distribution of analyzed plants by source water type vs. Phase II population

Water Quality Distribution of Write-ups								
Source Water	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
Fresh	305	75.1%	79	68.7%	27	67.5%	6	60.0%
Brackish	76	18.7%	24	20.9%	5	12.5%	1	10.0%
Saline	25	6.2%	12	10.4%	8	20.0%	3	30.0%
Total	406	100.0%	115	100.0%	40	100.0%	10	100.0%

Table 4-2d: Distribution of analyzed plants by plant size vs. Phase II population

Plant Size Distribution of Write-ups								
Plant Size, MW	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
< 200	101	24.9%	19	16.5%	0	0.0%	0	0.0%
200 - 500	101	24.9%	27	23.5%	1	2.5%	0	0.0%
500 - 1,000	110	27.1%	39	33.9%	11	27.5%	3	30.0%
> 1,000	94	23.2%	30	26.1%	28	70.0%	7	70.0%
Total	406	100.0%	115	100.0%	40	100.0%	10	100.0%

Table 4-2e: Distribution of analyzed plants by region vs. Phase II population

Regional Distribution of Write-ups								
Region	Fossil				Nuclear			
	Phase II Facilities		Write-ups		Phase II Facilities		Write-ups	
	Number	%	Number	%	Number	%	Number	%
Mid-Atlantic	35	8.6%	11	9.6%	10	25.0%	2	20.0%
Midwest	87	21.4%	25	21.7%	4	10.0%	1	10.0%
North Central	69	17.0%	15	13.0%	7	17.5%	2	20.0%
Northeast	66	16.3%	18	15.7%	9	22.5%	2	20.0%
Northern Plains	4	1.0%	0	0.0%	0	0.0%	0	0.0%
Pacific	22	5.4%	16	13.9%	2	5.0%	1	10.0%
South Central	52	12.8%	12	10.4%	2	5.0%	0	0.0%
Southeast	70	17.2%	18	15.7%	6	15.0%	2	20.0%
Southwest	1	0.2%	0	0.0%	0	0.0%	0	0.0%
Total	406	100.0%	115	100.0%	40	100.0%	10	100.0%

Brief analyses of each of the selected plants are included in Appendix E. Chapter 5 gives a review of the general approach to the analyses and a summary of the important conclusions.

References-- Chapter 4

4.1 Personal communication, T. Dendy, SPX Corporation, July, 2008

4.2 Sanderlin, D. and F. Ortega, "Dry Cooling History in North American Power Plants", Presented at Dry Cooling for Power Plants--Is This the Future?; Air and Waste Management Association Conference; San Diego, CA, May, 2002.

4.3 Enercon Service, Inc., "Diablo Canyon Power Plant; Cooling Tower Feasibility Study, March, 2009.

4.4 Enercon Services, Inc., "Feasibility Study for Installation of Cooling Towers and the San Onofre Nuclear Generating Station", 2009.

5

SITE-SPECIFIC ANALYSES

Approach

Analyses were performed to generate retrofit cost estimates for 125 specific plants chosen to represent the family of Phase II facilities as discussed in Chapter 4 and presented in Tables 4.1 through 4.2. The plants chosen for analysis are listed in Appendix D. The analyses were done by using the information provided by the plants in the cost information worksheets to assess the effect of the eleven site-specific features identified in Chapter 2 as influencing the degree of difficulty of a closed-cycle cooling system retrofit at the individual plant. A brief summary of the considerations is given below.

General observations

Although the degree of difficulty of a retrofit is very specifically related to the situation at each given site, some general trends are evident.

Nuclear vs. fossil

Retrofit costs at nuclear plants are generally higher for a given size plant than the corresponding costs at fossil plants. This is true for a variety of reasons. First, the cooling load in Btu/MWh is higher for nuclear plants as a result both of the lower cycle efficiency and the fact that some of the rejected heat at a fossil plant goes out through the stack and not the condenser. Therefore, the typical circulating water flow at a nuclear plant is significantly higher (675 gpm/MW for nuclear vs. ~500 gpm/MW for fossil) and hence the condenser water cooling system is correspondingly larger.

However, even on a normalized $/gpm basis the nuclear costs are higher as shown in Figure 3-5. Although the reasons for this were not explored in depth, it would seem reasonable that the regulatory oversight at nuclear plants would be more intensive; the design and construction practices more rigorous; the inspections more extensive; the quality control requirements more stringent and vigorously enforced.

In addition, the studies from which the retrofit cost data were obtained tend to be more extensive and more recent for the set of nuclear plants used to develop the cost correlations than were those for the fossil plants. To the extent that this is an important factor in the cost differential, it may be expected that as more elaborate and up-to-date studies are performed for large fossil plants, the costs may rise to a level more comparable to the nuclear ones. However, at this time, there is no credible basis for adjusting the fossil costs other than simple scaling from the date of the studies to the present.

Neighborhood characteristics

In general, more spacious and less congested sites result in less difficult, less costly retrofits. This translates into the result that sites in remote, rural locations typically fall at the "easier" end of the difficulty scale presumably because the availability and cost of land in such locations is much more favorable to large, open site plans than plants in urban locations or in areas near oceans or lakes or residential communities where the land is more costly and dedicated to other uses.

Analyses of selected plants

As discussed in Chapter 4, approximately 185 plants returned cost estimation worksheets with varying amounts of site-specific detailed descriptive information. Of those, 125 plants were selected as forming a group that was reasonably representative of the family of Phase II facilities. An examination of each of these plants was made and a brief analysis of each is provided in Appendix E. The objective of each plant-specific analysis was to assign a degree of difficulty to a closed-cycle retrofit at that individual plant. Some of the general conclusions are summarized here.

Difficult sites

The most frequent reason for concluding that a site would be in the "Difficult" category was a combination of limited space on the site for locating a cooling tower, a large distance from the existing condensers and the likely site of the tower and, particularly, the presence of existing infrastructure in congested areas between the tower site and the turbine hall. This was often the case in older, urban plants.

Other situations included coastal plants, for a variety of reasons. First and foremost, coastal areas are often considered highly desirable locations for recreational purposes, the aesthetic beauty of coasts is often a treasured attribute and, in many cases, residential or tourist accommodations have gown up in the vicinity. In these cases, the addition of a large structure such as a cooling tower often accompanied by frequent, visible plume emissions requires plume and noise and abatement which can add significantly to the difficulty and cost of a closed-cycle cooling installation.

Drift control can add significantly to the difficulty of retrofits. This is particularly the case at sites with primary water sources which are saline or brackish. If either off-site drift damage to sensitive areas or fine particle (PM-10) regulations make it infeasible to use brackish or saline make-up, the alternative may be the use of reclaimed water from municipal, agricultural or industrial facilities. The cost of obtaining such water supplies and installing pipelines to bring the water to the site can be prohibitively costly.

A second feature is that near-coastal land is often soft, saturated ground which makes the trenching and the installation of underground piping far more difficult and expensive than comparable installations at inland sites.

Easy sites

The easiest sites are typically those in remote rural areas with few neighbors and large, uncongested sites. Such sites are found more frequently in the southeast, mid-west and south central areas. In such cases, some attention must be paid to the geologic characteristics of the soil since some are underlain with rock ledge which makes the installation of underground piping difficult.

Space Constrained Sites

There are some sites where the installation of closed-cycle cooling is simply infeasible due to a lack of the space required to install closed-cycle cooling. In the majority of cases, these sites are located in dense urban locations where there is simply no space available on the site to locate a cooling tower of sufficient size and the surrounding land is occupied, often with valuable urban properties such as apartment or office buildings. However, in other cases, at rural sites, while the existing facility site itself has no room for a cooling tower there may be open, undeveloped adjacent land. In such cases it may be possible to acquire additional land, unless it is a sensitive area such as unique habitat or a state or federal park. In this study the assumption has been made that if new land must be acquired in order to site a tower, this would render the site "infeasible for retrofit".

Seven examples are provided for illustrative purposes of space constrained facilities, where a retrofit is considered infeasible. Figures 5-1 through 5-5 show plants in major urban areas. It was beyond the scope of this study to document the exact number of facilities where space constraints have the potential to make retrofitting infeasible.

Figure 5-1 is a 1,340, four unit plant with two coal-fired and two oil/gas units located in the Northeast in a combined commercial/industrial area on the bank of a major river. The site is highly congested with the only open area in a parking lot. The surrounding area is equally congested with no apparent opportunity for off-site parking if the on-site lot were to be taken to install a cooling tower.

Figure 5-1: Space constrained site; Plant No. F465

Figure 5-2 is a 113 MW plant with two oil-fired units located on an ocean harbor. It is in a crowded, downtown environment surrounded by commercial office buildings, retail stores some residential apartment/condominium complexes and a boat harbor. No space for a cooling tower is available anywhere on the site. While some open space is seen at both ends of the plant site, these are parks and urban "green space" and absolutely unavailable for plant purchase and use.

Figure 5-2: Space constrained site; Plant No. F485

Figure 5-3 is a coal fired plant with a single 348 MW unit. It is located in a mixed urban environment of industrial and commercial facilities with some residential areas nearby. The boundary shown in Figure 5-3 creates an irregular, patchwork plot plan as the result of having sold portions of the plant site in the past. The remaining site property has no adequate space for a tower contiguous to the turbine halls and only limited space at the far corners of the site.

Figure 5-3: Space constrained site; Plant No. F382

Figure 5-4 is an oil fired facility consisting of three once through cooling units totaling approximately 64 MW. The facility is located in the downtown area of a large northeastern city. The adjacent property and surrounding blocks are fully developed and/or consist of important roadways. EPA Region staff determined that a retrofit at this facility was infeasible due to space constraints

Figure 5-4: Space constrained site; Plant No. F124

Figure 5-5 is a coal fired facility consisting of five once through cooling units totaling 514 MW. This facility is located in a densely populated mid-Atlantic city. The facility property boundary is shown in the figure. The facility is surrounded by a combination of high-rise apartment buildings to the north, major roads to the west, apartments and other building to the South and a large tidal river and some federal parkland to the east and south along the shoreline

Figure 5-5: Space constrained site; Plant No. F235

Plants shown in Figures 5-6 and 5-7 are in small to mid-sized cities but located on land extending out into the neighboring water bodies. The plant in Figure 5-6 is a small, 65 MW plant with four units on once-through cooling. As indicated in Figure 5-6, the plant property is divided into three neighboring, but not adjoining, parcels separated by roadways. Only the central parcel would be a usable location for a cooling tower and it is completely full with existing structures.

Figure 5-6: Space constrained site; Plant No. F356

Similar observations apply to the site shown in Figure 5-7 sited on the shore of, and extending into, a man-made lake. There are two plants on the site consisting of five units with a total capcity of approximately 465 MW operating on once-through cooling. The site is tightly constrained on all sides by water or highways and all available space within the site boundary is in use for the existing plant operations.

Figure 5-7: Space constrained site; Plant No. F390

6

VALIDATION OF CAPITAL COST ESTIMATES

As described in Chapter 2, the methodology for estimating the capital cost of cooling system retrofit at an individual plant developed in this study consist of two basic steps. The first step establishes a likely range of capital costs simply as a function of the circulating water flow rate in the original once-through cooling system. Separate cost relationships were determined for Fossil and nuclear plants. As described in Chapter 3, these cost relationships were objectively derived on the basis of independent cost information for 79 plants obtained from a variety of sources.

The second step requires placing an individual plant within the likely range of costs on the basis of the perceived degree of difficulty of a retrofit at that plant. This assignment of a degree of difficulty is based on site-specific information obtained from individual plants through the distribution of a cost estimating worksheet as described in Chapters 4 and 5. This step is more subjective and employs the application of engineering judgment. It is this step which must be tested and validated in order to establish confidence in the results of this study.

Approach to validation

There is a set of 35 plants for which both independent capital cost information and site-specific information adequate to assign a degree of difficulty are available. For these plants, estimates made following the method described in Chapters 4 and 5 were compared with the independent cost estimates obtained from other sources.

The plants used in this process of comparison and validation are discussed in three groups. These are:

- Nine plants for which either actual retrofit costs or costs determined from highly detailed engineering studies are available.
- Fifteen ocean plants on the California coast
- Additional plants evaluated as part of this study on the basis of information provided by the plants in the cost estimating worksheets.

Detailed plant studies

Nine plants were given special attention. These are the plants for which either actual costs were available from retrofits that had been done at the site or from very thorough and well documented engineering studies by experienced engineering firms or the utility's engineering department. The comparison of this information with the estimates performed using the worksheet information were used as a means of quality control on the method and as a means of calibrating the judgment used in giving weight to the effect of the eleven different factors. The results and the guidance obtained from the analyses of these nine plants are summarized below.

Table 6.1 lists the plants and their characteristics. For these plants, in addition to the material requested in the cost estimation worksheet, more detailed cost and design information was provided. In some cases, additional information in the form of complete engineering study reports was made available. For two of the plants at which retrofits had actually been done, site visits were made.

Table 6.1: Plants with detailed cost information

Plant	Fuel	Capacity	Cooling water Flow	Source Water	State	Cost Source
		MW	gpm			
FOS1	Coal	292	154,000	River/Fresh	WV	Actual
N321	Uranium	2,298	1,736,111	Ocean/Saline	CA	Eng'g study
F275	Coal	800	380,000	River/Fresh	GA	Eng'g study
FOS4	Coal	235	144,000	River/Fresh	KS	Actual
F483	Coal	1,170	792,000	GL/Fresh	WI	Eng'g study
N218	Uranium	2,540	2,200,000	River/Brackish	NJ	Eng'g study
N233	Uranium	1,296	452,000	Ocean/Saline	NH	Eng'g study
F546	Coal	976	588,067	River/Fresh	IL	Actual
FOS5	Coal	550	460,000	River/Fresh	GA	Actual

The cost information is compiled in Table 6.2. The several cost categories were those common to most sites. However, the costs were reported in different formats by different plants, and the categories are not all used by every plant. Even when they are, they do not necessarily contain exactly the same cost elements in each case.

Many of the factors for those costs over and above the "Installed Equipment Subtotal" are factored as a specified percentage of some or all of the equipment costs. The chosen factors [as, for example the Contingency, Escalation, AFI ("Adjustment for Inflation"), AFUDC ("Allowance for Funds Used During Construction"), Owners Costs and others] were not the same for every plant.

Comparisons with estimates

In order to compare the detailed cost data with the estimated costs for these plants, it is necessary to understand which cost elements were included in the cost data that were used to develop the correlations. In this regard, two considerations are important.

The first is whether or not the independent cost estimates included items in addition to the simple cost of the installed equipment. At the time some of the data were assembled in 2002 (6-1), plant personnel for many of the plants were contacted in an attempt to determine whether the costs included items such as Engineering, Contingency, Escalation, AFI and AFUDC. In some cases, this could not be determined. In most cases, the figures included Engineering and Contingency but not an explicit allowance for Escalation, AFI or AFUDC.

The second consideration was whether the cooling tower costs were for conventional towers or for plume-abated towers. It was determined that none of the independent cost data upon which the cost relationships were based included plume-abatement.

Therefore, in making the comparisons, the reported costs were adjusted by subtracting the AFI, AFUDC and Escalation quantities from those plant totals where they were specifically identified and accounting for the effect that these deductions have on the Contingency. The Contingency was included while recognizing that it may well have been computed on a basis very different from what was typical of the data upon which the cost relationships were based. For those cases where plume abatement towers were assumed, the cooling tower costs were reduced by a factor of x 2.5

A comparison of the project estimates with the adjusted costs provided by the plants is shown in Table 6.3. Plant N321 represents a retrofit of extremely high cost as was discussed in Section 5. It is excluded from the comparisons. Of the eight remaining comparisons, the estimates were low in three cases and high in five cases. Six of the estimates were within +/- 10%, seven within +/- 25%. One of the estimates differed from the reported costs by more than 50% on the high side.

Plant ID	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5
Fuel	Coal	Nuclear	Coal	Coal	Coal	Nuclear	Nuclear	Coal	Coal
MW	292	2,298	800	235	1,170	2,540	1,296	736	550
Source water	River/Fr	Ocean/Sa	River/Fr	River/Fr	GL/Fresh	River/Br	Ocean/Sa	River/Fr	River/Fr
OTC Flow, gpm	154,000	1,736,111	380,000	144,000	792,000	2,200,000	452,000	588,067	460,000
Capital Costs (Date)	2006	2008	2005	2005	2007	2005	2008	2008	2001
Cooling tower(s)	$5,249,000	$242,100,000	$15,186,000	$4,319,000	$155,342,000	$61,849,000	$110,652,000	$23,184,000	$16,450,000
Cooling tower basin(s)	$1,252,000		$2,128,000	$1,638,000	$20,073,000	$22,394,000	$7,946,000	$8,250,000	$2,359,000
Piping and valves	$1,983,000	$178,800,000	$19,027,000	$2,418,000	$32,514,000	$127,574,000	$20,308,000	$12,196,000	$18,560,000
Pumps	$626,000	$72,000,000	$2,577,000	$884,000	$10,876,000	$74,310,000	$28,574,000	$7,751,000	$7,831,000
Condenser modifications	$0	$83,800,000	$0	$49,000	$0	$135,216,000	$0	$0	$0
Electrical	$4,279,000	$100,900,000	$11,322,000	$2,355,000	$12,323,000	$32,561,000	$8,450,000	$14,556,000	$10,458,000
Miscellaneous						$0	$0		
Site development	$459,000	$586,600,000	$10,456,000	$9,649,000	$55,436,000	$0	$3,477,000	$13,145,000	$7,263,000
MU and BD systems	$4,352,000	$143,100,000			$394,000	$12,967,000		$511,000	
Chemical treatment			$428,000	$399,000	$506,000	$11,451,000		$565,000	$102,000
I&C	$365,000	$23,700,000		$218,000	$842,000			$2,917,000	
Fire and lightning protection			$1,110,000	$742,000				$36,000	
Security		$44,200,000			$4,248,000	$619,000			
Other	$960,000	$154,400,000	$689,000	$154,000			$535,000		$511,000
Installed equip't (Total)	**$19,525,000**	**$1,629,600,000**	**$62,923,000**	**$22,825,000**	**$292,554,000**	**$478,941,000**	**$179,942,000**	**$83,111,000**	**$63,534,000**
Escalation									
Labor	$0	$0	$0	$0	$5,195,000	$0	$0	$0	$0
Materials					$732,000				
Engineered equip't					$2,529,000				
Subcontracts					$2,030,000				
Escalation (Total)	**$0**	**$0**	**$15,598,000**	**$0**	**$10,486,000**	**$120,839,000**	**$0**	**$24,974,000**	**$0**
AFI					$30,304,000				
Indirects		$166,000,000		$191,000	$1,667,000				
Construction management	$2,296,000	$131,700,000	$6,830,000	$456,000	$7,538,000	$23,947,000	$4,590,000	$2,917,000	$4,924,000
Engineering		$74,700,000	$1,998,000	$1,262,000	$33,903,000	$47,894,000	$3,732,000	$15,556,000	$5,533,000
Startup & Commission		$50,000,000	$543,000		$0		$3,672,000	$972,000	$383,000
Transportation		$189,000,000			$7,809,000				
Equipment spares					$20,000		$5,416,000		
Other				$275,000	$976,000			$28,884,000	$3,045,000
PROJECT SUBTOTAL	$21,821,000	$2,241,000,000	$87,892,000	$25,009,000	$385,257,000	$671,621,000	$197,352,000	$156,414,000	$77,419,000
Contingency		$448,200,000	$17,579,000		$38,526,000	$141,336,000	$9,868,000	$21,995,000	$7,438,000
Owner's costs	$783,000		$579,000	$543,000	$0	$72,252,000			$2,628,000
AFUDC	$1,921,000		$16,350,000		$0				$6,236,000
TOTAL	**$24,525,000**	**$2,689,200,000**	**$122,400,000**	**$25,552,000**	**$423,783,000**	**$885,209,000**	**$207,220,000**	**$178,409,000**	**$93,721,000**

Table 6.2: Detailed cost elements

08702091

Plant ID	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5	"Eight Plant Total"
Total reported cost	$24,525,000	$2,689,200,000	$122,400,000	$25,552,000	$423,783,000	$885,209,000	$207,220,000	$178,409,000	$93,721,000	
Adjusted cost	$22,604,000	$2,689,200,000	$87,332,738	$25,552,000	$252,565,006	$741,412,613	$133,704,327	$153,434,330	$87,487,196	$1,504,092,210
Project estimate										
Fossil										
Easy	$27,874,000		$68,780,000	$26,064,000	$143,352,000			$106,440,127	$83,260,000	
Average	$42,350,000		$104,500,000	$39,600,000	$217,800,000			$161,718,425	$126,500,000	
Difficult	$62,370,000		$153,900,000	$58,320,000	$320,760,000			$238,167,135	$186,300,000	
More difficult	$87,780,000		$216,600,000	$82,080,000	$451,440,000			$335,198,190	$262,200,000	
Nuclear										
Less difficult		$475,694,414				$602,800,000	$123,848,000			
More difficult		$1,118,055,484				$708,400,000	$291,088,000			
Estimated degree of difficulty	Easy	"Extreme"	Easy to average	Easy	Average to difficult	Intermediate	Less difficult	Difficult	Easy	
Project estimate	$27,874,000	>$1,118,055,484	$86,640,000	$26,064,000	$269,280,000	$790,600,000	$123,848,000	$238,167,135	$83,260,000	$1,617,859,135
% difference	23.3%	na	-0.8%	2.0%	6.6%	6.6%	-7.4%	55.2%	-4.8%	7.6%

"Eight Plant Total" excludes N321

Table 6.3: Comparison of plant-provided costs with project estimates

Item	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5	8 Plant Average
Cooling tower(s)	$34.08	$139.45	$39.96	$29.99	$196.14	$28.11	$244.81	$39.42	$35.76	$81.04
Cooling tower basin(s)	$8.13	$0.00	$5.60	$11.38	$25.34	$10.18	$17.58	$14.03	$5.13	$12.17
Piping and valves	$12.88	$102.99	$50.07	$16.79	$41.05	$57.99	$44.93	$20.74	$40.35	$35.60
Pumps	$4.06	$41.47	$6.78	$6.14	$13.73	$33.78	$63.22	$13.18	$17.02	$19.74
Condenser modifications	$0.00	$48.27	$0.00	$0.34	$0.00	$61.46	$0.00	$0.00	$0.00	$7.73
Electrical	$27.79	$58.12	$29.79	$16.35	$15.56	$14.80	$18.69	$24.75	$22.73	$21.31
Miscellaneous	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Site development	$2.98	$337.88	$27.52	$67.01	$69.99	$0.00	$7.69	$22.35	$15.79	$26.67
MU and BD systems	$28.26	$82.43	$0.00	$0.00	$0.50	$5.89	$0.00	$0.87	$0.00	$4.44
Chemical treatment system	$0.00	$0.00	$1.13	$2.77	$0.64	$5.21	$0.00	$0.96	$0.22	$1.37
I&C	$2.37	$13.65	$0.00	$1.51	$1.06	$0.00	$0.00	$4.96	$0.00	$1.24
Fire and lightning protection	$0.00	$0.00	$2.92	$5.15	$0.00	$0.00	$0.00	$0.06	$0.00	$1.02
Security	$0.00	$25.46	$0.00	$0.00	$5.36	$0.28	$0.00	$0.00	$0.00	$0.71
Other	$6.23	$88.93	$0.00	$1.07	$0.00	$0.00	$1.18	$0.00	$1.11	$1.20
Total	$126.79	$938.65	$163.77	$158.51	$369.39	$217.70	$398.10	$141.33	$138.12	$214.21

Table 6.4: Cost elements expressed as normalized costs ($/gpm)

Item	Fos 1	N321	F275	Fos 2	F483	N218	N233	F546	Fos 5	8 Plant Average
Cooling tower(s)	26.9%	14.9%	24.4%	18.9%	53.1%	12.9%	61.5%	27.9%	25.9%	31.4%
Cooling tower basin(s)	6.4%	0.0%	3.4%	7.2%	6.9%	4.7%	4.4%	9.9%	3.7%	5.8%
Piping and valves	10.2%	11.0%	30.6%	10.6%	11.1%	26.6%	11.3%	14.7%	29.2%	18.0%
Pumps	3.2%	4.4%	4.1%	3.9%	3.7%	15.5%	15.9%	9.3%	12.3%	8.5%
Condenser modifications	0.0%	5.1%	0.0%	0.2%	0.0%	28.2%	0.0%	0.0%	0.0%	3.6%
Electrical	21.9%	6.2%	18.2%	10.3%	4.2%	6.8%	4.7%	17.5%	16.5%	12.5%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Site development	2.4%	36.0%	16.8%	42.3%	18.9%	0.0%	1.9%	15.8%	11.4%	13.7%
MU and BD systems	22.3%	8.8%	0.0%	0.0%	0.1%	2.7%	0.0%	0.6%	0.0%	3.2%
Chemical treatment system	0.0%	0.0%	0.7%	1.7%	0.2%	2.4%	0.0%	0.7%	0.2%	0.7%
I&C	1.9%	1.5%	0.0%	1.0%	0.3%	0.0%	0.0%	3.5%	0.0%	0.8%
Fire and lightning protection	0.0%	0.0%	1.8%	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%
Security	0.0%	2.7%	0.0%	0.0%	1.5%	0.1%	0.0%	0.0%	0.0%	0.2%
Other	4.9%	9.5%	0.0%	0.7%	0.0%	0.0%	0.3%	0.0%	0.8%	0.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 6.5: Cost elements as percentage of total equipment cost

The aggregated estimates for all eight plants agreed to within less than 8%.

Tables 6-4 and 6-5 display the costs in two different ways. Table 6-4 lists the individual cost elements expressed as normalized cost per unit flow ($/gpm) which is the correlating basis used in the study to estimate total project costs. Table 6-5 displays the cost of each element as a percentage of the total project cost. The right hand column in each table is the average of the respective values in each table for eight of the nine plants excluding N321. N321 was excluded to avoid distorting the averages with a retrofit of extreme difficulty and extraordinarily high costs. However, the values for the plant are displayed in the table as an example of what retrofit costs can be at unusually difficult sites.

For most sites, of the 14 cost elements, four groups account for nearly all the cost. These are the cooling tower and basin, the recirculating water systems (pumps plus piping and valves), the site development costs and the electrical costs. Using the average values these four cost groups account for over 90% of the total costs. These four cost elements will be discussed separately.

Cooling tower and basin

Of the 9 plants, the cooling tower costs for 6 of them range from $28 to $40 per gpm, which is a reasonable range for counterflow, mechanical draft towers without plume abatement. For Plants N321, F483 and N233, the reported costs were $140/gpm, $196/gpm and $245/gpm respectively. In the latter two cases, the reported costs were for plume abatement tower which commonly cost 2.5 to 3 times non-abated towers. However, even if both costs are reduced by a factor of 3, those costs are still $65/gpm and $82/gpm respectively, well above the normal range.

Plant N321 reported costs for the towers themselves was only $46/gpm is reasonably consistent with the other sites, especially given that the tower will operate on seawater make-up. However, the underlying report contains additional costs for “mechanical”, “electrical” and “fans” which essentially triple the reported cost of the tower. These costs significantly exceed any corresponding costs in other reports, and there is no available information to evaluate them.

The underlying report on the retrofit costs for Plant F483 indicates that the location of the towers required the demolition and removal of retired units. It may be that some of these costs were allocated to the towers themselves rather than to a “Site Development” category.

Plant N233 reports the highest tower costs even after an adjustment to account for plume abatement. Two factors may contribute to the cost. First, the tower will operate on seawater make-up. Second, the plant is located near the coast in what appears to be flat, marshy ground with a presumably high water table. Therefore, a possible reason for the elevated cost may be the costs of foundation preparation or pilings needed to support the tower and basin. Given the very low amount allocated to Site Preparation, the costs may be included in the tower costs.

The basin costs for 6 of the 9 units range from \$5/gpm to \$14/gpm. For a simple assumption of 500gpm/MW and 15,000 gpm per tower cell and cell dimensions of 50' x 50', a normalized basin cost of \$10/gpm translates to \$60/ft^2. A range of \$5 to \$14/gpm translates to \$30/ft^2 to \$84/ft^2 which is reasonably consistent with commonly reported costs of \$40 to \$50/ft^2. Two plants (F483 and N233) report substantially higher costs of \$18/gpm and \$25/gpm respectively [\$108/ ft^2 and \$150/ ft^2].and are two of the three plants reporting the high tower costs. As before, it may be that site preparation costs were included in the basin costs and, in the case of N233, that site soil conditions required special foundation work. In any case, using the numbers as reported for 6 of the 9 plants, the tower/basin costs accounted for 17.6% to 37.8% of the total retrofit costs with an average of 24.3%.

Circulating water system (pumps, piping and valves)

The costs of the circulating water systems are highly variable on both a normalized (\$/gpm) basis and as a percentage of the total equipment costs. While the fundamental size of the piping, valves and pumps is related directly to the water flow rate, the location of the tower relative to the existing condenser, the elevation change from the condenser discharge to the tower distribution deck and the site soil conditions into which the piping must be installed are entirely site-specific. The normalized costs for 8 of the 9 plants vary from \$17 to \$108/gpm; the costs as a percentage of the total vary from 13% to 42%. These costs, along with the Site Preparation costs which is discussed below, are a major source of the site-specific variability in retrofit costs.

Site preparation

Site preparation costs are the most highly variable of the major cost elements ranging from 0% in one case to over 42% in another with an average of 15%. While the "0%" figure undoubtedly means that the site preparation costs were included implicitly in other elements, two plants report 1.9% and 2.4%. It is this factor, along with the circulating water system costs, that accounts for the highly site-specific nature of the retrofit costs and for the high degree of variation in the cost from the "Easy" to "Difficult" or "More Difficult" projects.

Electrical

The costs categorized as "Electrical" are primarily associated with the cost of providing additional station power and motor control centers for the cooling tower fans and the increased pump power requirements. As will be discussed in more detail in Section 7, this additional power is almost directly proportional to the circulating water flow. Therefore, on a normalized (\$/gpm) basis the cost should be relatively constant from site to site. For 8 of the 9 sites (excluding again N321) the normalized electrical cost ranges from \$15 to \$30/gpm with an average of \$23/gpm, all within a range of +/-25 to 30%.

Individual plant estimates

For Plant FOS1, even the "Easy" designation resulted in an overestimate of the costs by nearly 20%. The data used in the cost factor development presented in Chapter 3 does indicate that a number of cases are, in fact, less costly than the "Easy" correlation, but there was no basis in any of the site-specific estimates to conclude that a particular case was "exceptionally easy". Therefore, the lowest estimate ever assigned was that consistent with an "Easy" designation.

Plant N321 represents an extreme case. As noted in Section 3 as part of the discussion on development of the cost relationships, the reported costs were much higher on both an absolute and normalized basis than for any other site. This is due in large measure to the highly irregular terrain on which the plant is built and its isolated location which makes it difficult and costly to bring equipment, materials and the labor force to and from the plant. The total costs were excluded from the cost function development on the grounds that including them would inflate or otherwise bias the cost relationship for other, less extreme sites. Herein, the costs and cost elements are included in the tables and the discussion for illustrative purposes and to provide an example of how costly cooling system retrofits can be in some situations, but excluded from the averages on the same basis for which they were excluded from the correlation analysis.

For Plants F275 and FOS 5, the estimates were satisfactory and both within 5%. In both cases, the costs for "Piping and Valves" were a higher fraction of the total equipment costs than appears typical. In the case of Plant FOS 5, where the retrofit was actually performed, the decision was made to use a single set of pumps to pump the water through the condenser and to the top of the tower in a single lift. This required reinforcement of the condenser and some of the existing circulating water tunnels and replacement of the existing circulating water pumps. This would be expected to result in a somewhat higher cost than the alternate approach described in Chapter 2. It is assumed that the estimates for FOS 2 used the same approach.

For Plants F483 and N233, the reported costs included the installation of plume-abated towers. The data upon which the cost relationships were based does not include any cases using plume abatement towers. Since plume-abated towers are expected to cost between 2 and 3 times the cost of standard towers, the estimates were adjusted by reducing the cooling tower costs by a factor of 2.5. The effect on the total project costs is seen to be significant. In both cases, the adjusted costs and the estimated costs based on the determined degree of difficulty was within 10%. Another approach would have been to adjust the degree of difficulty to Difficult or More Difficult to account for the need for plume abatement. This was not done because the site analysis for this study did not conclude that plume abatement would be necessary even though the reported study done for the plants chose to include it. Therefore, to maintain consistency in the rating methodology, the lower degree of difficulty was assigned and the reported costs adjusted in a plausible way for purposes of the comparison.

For Plant FOS 2, the retrofit was determined to be "Easy". The agreement was satisfactory, within 2%, even though the site development costs were a high percentage of the total, a situation normally associated with more difficult retrofits. Therefore, the close agreement was likely somewhat fortuitous.

Plant N218 requires special discussion. The reported retrofit costs are significantly different from the other 8 plants in that the cooling system has been re-optimized, as discussed in Section 4, Item 11. In this case the circulating water flow in the new closed-cycle systems is one-half that of the circulating water flow in the original once-through cooling system. As would be expected, the cooling tower is smaller and cheaper than it would have been if the system has not been re-optimized and the cooling water flow kept at its original level. The normalized costs in Table 6.4 use the original flow rate. Had the new, lower flow been used the normalized costs in $/gpm would be double those listed but the individual element costs, listed in Table 6-5 as a percentage of the total cost would remain the same.

This has the effect of raising the normalized tower costs to $56/gpm and the basin cost to $20/gpm or $120/ft^2. These costs are at the high end of the range but are not unreasonable for a tower on brackish make-up and at a near-coastal site with a high water table. Two items are noteworthy. First, the lower cooling tower cost is more than made up for by the high cost of condenser modification. ($135,000,000 vs. $62,000,000). As noted in Table 6.4, the total reported capital cost of $885,000,000 exceeds the "More Difficult" estimate by approximately 25% if the closed-cycle cooling water flow rate is used in the estimating cost function. A plausible approach to estimating the cost is to use the correlation equation with the lower flow rate for the determined degree of difficulty for all the costs other than the condenser modification and then adding the condenser modification cost to the result. If this approach is adopted the total estimated retrofit cost is $790,600,000 ($655,600,000 + $135,000,000) which is within 7% of the reported cost of $741,413,000.

For Plant F546, the information available indicated a site with limited space and a congested area between the likely location of the tower and the existing condensers which would lead to high costs for the installation of the circulating water lines. Evidently, a detailed, on-site assessment enabled the engineering firm to find a simpler approach with significantly lower costs. It is consistent with the general approach and conclusions of this study that site-specific conditions dominate the costs and that there will be situations in which generalized, at-a-distance estimates of the type used in this study, will seriously under- or over-estimate the costs. This is simply one of those cases.

California ocean plants

A previous study of estimated retrofit costs for coastal plants in California was conducted in 2007 (6-2). Essentially the same methodology was used in that study as in the current study. Concurrently, another study of the California ocean plants was sponsored by the

California Ocean Protection Council and conducted by TetraTech Corporation (6-3). The methodology in that study was a more "bottom-up" approach to cost estimating in which each site was either visited or plant drawings were examined in detail, a specific approach to retrofit was assumed, and a cost estimate was constructed based on detailed bid sheets by a qualified engineering firm. Detailed descriptions of the methods and results of both studies are available in the above references.

Direct comparisons of the estimated costs from the two studies were possible at 15 of the California coastal plants. The total costs of retrofit for all 15 plants agreed within 5% suggesting that there was no systematic bias in the more generalized estimating methodology of this study. Figure 6-1 shows a comparison of the results for the 15 plants.

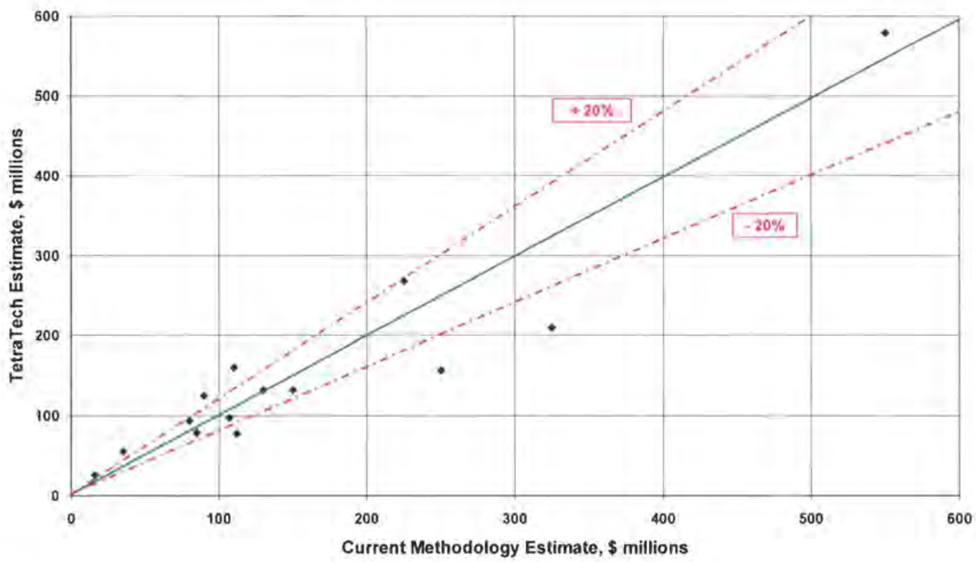


Figure 6-1: Comparison of retrofit cost estimates for California coastal plants

Most of the comparisons are within +/-25%. In two cases the estimates differed more significantly with the current methodology giving estimates that exceeded the TetraTech estimates by over 50%. In both cases, the difference was largely attributable to the fact that the current estimate was weighted to the "Difficult" level because of the judgment that plume abatement would be required at the sites while the TetraTech estimate assumed standard, non-abated cooling towers. Additional differences in assumptions regarding the location and number of cooling towers required accounted for much the remaining difference in the estimated costs. On balance, the agreement is judged to be satisfactory.

Additional selected plants

In addition to the eight detailed plants and the 15 California ocean plants discussed above, there are an additional 34 plants for which adequate site-specific information and independent cost estimates were available. Assessments of the degree of difficulty and estimates of the capital cost of retrofit were developed for each these plants using the approach described in Chapters 4 and 5.

Table 6-4 lists all 57 plants. These plants are a subset of the 79 plants used to establish the cost ranges as described in Chapter 3. Direct comparisons were made between the independent cost estimates and the current study estimates resulting from the application of the methodology developed herein. The cost estimates presented are the capital costs only and do not include additional costs of operating power, cooling system maintenance, plant efficiency loss, plant outage time and permitting.

Figure 6.2 plots the independent cost estimate against the estimate developed using the methodology of this study. Two items are noteworthy. First, the totals of the capital costs for all **57** plants show essentially perfect agreement----$7,115,000,000 from the independent sources vs. $7,679,000,000 using the estimating methodology---or an agreement to within less than 8%. Similar agreement is found for the total retrofit costs in the two sub-groups discussed above providing support for the conclusion that there is no systematic bias in the estimating methodology and that reliable results are obtainable on an aggregate basis.

The quality of the agreement for individual plants is varied as would be expected considering the important influence of site-specific conditions at every site. Of the plants for which comparisons were made, the methodology developed in this study differed from the independent assessments from various sources on the high side in 19 cases and on the low side in 18. In 15 cases the differences were more than +/- 20% with five on the high side (> +20%) and ten on the low side (< -20%). Of the five nuclear plants, only one differed by more than 20%. The sites with the highest differences were primarily those with crowded plant conditions located in urban areas on the coast. In these cases, the magnitude of the difficulties posed by site geology, space availability and the presence of underground interferences is very difficult to judge based on interpretations of aerial photos and simple plot plans. Any differences in judgment can lead to large differences in the assumed degree of difficulty and estimated cost.

The differences between estimates produced using the methodology of this study and the results of independent estimates at plants for which they were available were both on the high side and the low side. Therefore, it is concluded that, while the differences at individual sites can be significant, there is no evidence of any systematic bias in the methodology, suggesting that confidence can be placed in aggregated totals.

Plant ID	Circulating Water Flow	Degree of Difficulty	Estimated Cost	Reported Cost
	gpm		$	$
Nuclear				
N321	1,736,111	Extreme	na	$2,689,000,000
N178	1,886,000	Less D	$516,764,000	$558,151,000
N218	2,200,000	Int	$1,009,800,000	$885,210,000
N302	1,621,528	Int	$744,281,250	$614,558,000
N233	452,000	Int	$207,468,000	$225,000,000
N459	974,600	More D	$627,642,400	$590,672,000
Fossil				
Fos 6	270,000	E to Av	$60,345,000	$51,900,000
Fos 5	460,000	E to Av	$102,810,000	$121,000,000
Fos 2	144,000	Av	$39,600,000	$31,000,000
Fos 1	154,000	Easy to Average	$34,419,000	$25,000,000
F540	560,500	E	$101,450,500	$152,117,000
F535	545,486	Av to D	$228,558,634	$155,118,000
F509	475,694	Av	$130,815,972	$142,000,000
F486	508,000	D	$205,740,000	$159,000,000
F483	792,000	MD	$451,440,000	$423,782,000
F449	870,000	Av to D	$364,530,000	$368,768,000
F445	810,000	Av to D	$339,390,000	$287,900,000
F439	800,200	Difficult	$324,081,000	$225,013,000
F433	786,200	Av	$216,205,000	$105,200,000
F424	740,000	Av	$203,500,000	$142,294,000
F420	704,167	D	$285,187,500	$162,800,000
F408	642,000	Av	$176,550,000	$134,429,000
F387	177,600	E to Av	$39,693,600	$25,164,000
F382	224,306	MD	$127,854,167	$128,533,000
F348	365,277	D	$147,937,185	$169,376,000
F341	167,400	E to Av	$37,413,900	$59,500,000
F318	148,000	Av to D	$62,012,000	$145,792,000
F283	400,000	Av to D	$167,600,000	$251,920,000
F281	392,000	Av to D	$164,248,000	$171,520,000
F277	382,000	Average to Difficult	$160,058,000	$155,118,000
F275	380,500	E to Av	$85,041,750	$102,000,000
F256	356,944	D	$144,562,500	$142,100,000
F252	343,750	Av to D	$144,031,250	$160,500,000
F155	56,400	Av	$15,510,000	$27,900,000
F146	70,000	E	$12,670,000	$14,268,000

Table 6-6
Comparisons with independent estimates

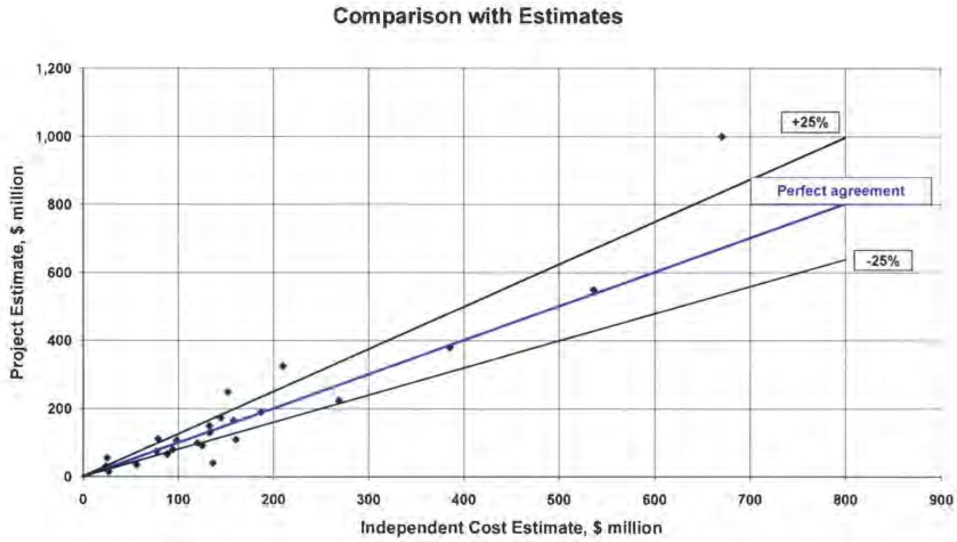


Figure 6-2
Plot of comparable cost estimates

References-- Chapter 6

6-1: *Cooling System Retrofit Cost Analysis*, EPRI, Palo Alto, CA, Technical Update 1007456, 2002

6-2: *Issues Analysis of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling: California Coastal Plants*, EPRI, Palo Alto, CA 2007. TR-052907

6-3: California's Coastal Power Plants: Alternative Cooling System Analysis, *Tetra Tech, Inc., Golden CO; T. Havey, Project Manager, Prepared for California Ocean Protection Council, February, 2008. (Available at http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml):*

7

OTHER RETROFIT COSTS

Introduction

The simplest approach to retrofitting once-through cooled plants with a closed-cycle cooling system, as described in Chapter 2, retains the existing condenser and circulating water pumps and operates at the same circulating water flow rate as the original once-through system. This study assumes that the cooling cycle is closed by installing a mechanical-draft, counterflow cooling tower, new circulating water lines between the condenser and the tower, new circulating water pumps and a sump for the condenser discharge flow, if needed. Modifications are made to the existing inlet/discharge piping, tunnels and structures as required to accommodate make-up and blowdown from the cooling tower and to integrate the newly installed tower loop with the existing condenser loop. This is illustrated in Figures 2-1 and 2-2.

This is the approach that was adopted in nearly all of the 79 retrofit projects for which the cost estimates that formed the basis of the cost functions. Therefore, the retrofit project costs developed herein are implicitly based on the assumption that this approach will be taken in all cases.

This approach typically incurs the lowest initial capital cost, requires the minimum amount of downtime and is the least disruptive to plant operation both during and after the retrofit. However, in addition to the initial capital cost, other costs are incurred. These include the cost of increased operating power and maintenance, the costs of reduced plant efficiency imposed by the higher condenser operating temperatures normally imposed by the retrofit and the cost of plant downtime during the installation of the retrofitted system. While a rigorous analysis of these costs is beyond the scope of this study, some general estimates are subsequently provided.

In addition, there are alternative retrofit approaches which may be preferred in some specific situations. Among these are designing for a different circulating water flow and modifying the condenser accordingly, the selection of a natural-draft cooling tower as opposed to a mechanical-draft tower or the adoption of a hybrid or dry cooling system in place of an all-wet, closed-cycle cooling system. While none of these will be examined in detail, a brief discussion of each follows.

Finally, there are a number of items such as regulatory, permitting and environmental issues which affect the total cost of retrofit in ways which are difficult to quantify generically but nonetheless can be significant. They are also briefly reviewed.

Cost of increased operating power requirements

The additional operating power required by a closed-cycle cooling system using a wet, mechanical-draft cooling tower consists of two parts: pumping power and fan power.

Increased pumping power

As described in Chapter 2 and illustrated in Figure 2-2, the pumping power for the retrofitted system consists of both the power used by the original once-through cooled system, which remains essentially unchanged in most cases, and the added power required to pump the circulating water from the condenser exit to the top of the cooling tower. From there it is assumed that the water returns to the intake of the original circulating water pumps by gravity. A small amount of additional power is required to provide make-up to the closed-cycle system and to discharge blowdown form the system. However, these flows are a small fraction (typically less than 5%) of the recirculating flow, and this additional power is neglected in these estimates.

Consistent with that approach, the additional pumping power required is a function simply of the circulating water flow rate and the head required to convey the water from the condenser discharge sump to the distribution deck of the cooling tower. The head required is made up of the elevation change from the intake to the distribution deck plus the frictional pressure drop in the circulating water line to the tower. Both of these vary depending on the circulating water flow rate of the existing once-through system and the layout of the newly installed closed-cycle system. Some general rules-of-thumb are used to estimate the magnitude of this additional pumping power requirement.

Table 7-1 gives a reasonable range of flow rates, tower heights and separation distance of the tower from the condenser encountered at a range of plant and site conditions.

Table 7-1: Range of pumping power estimating parameters

Typical range	Circulating water flow (gpm/MW)	Elevation Change (ft)	Distance to Tower (ft)
Minimum	400	30	500
Intermediate	600	45	1000
Maximum	800	60	2000

The range of circulating water flow rates is based on the information presented in Figure 3-2. A typical height of the distribution deck above grade at the tower location ranges from 25 feet for an in-line configuration to 35 to 40 feet for a back-to-back arrangement. In the case of plume abatement towers, the lift is greater still, but some designs utilize a siphon effect to reduce the pumping requirement. In addition, the tower must be placed somewhat above the condenser location to allow for gravity drain of the cold water back to the condenser, and the condenser discharge bay or sump from which the new circulating pumps draws is typically below the condenser intake level. The range of separation distances from the condenser to the tower is consistent with site-specific examinations as described in Chapter 5. The frictional pressure drop over this distance is based on the assumption of a pipe size designed for a typical flow velocity of 9 feet/second. Finally a combined pump/motor efficiency of 76.5% (a motor efficiency of ~ 90% and a pump efficiency of ~ 85%) is assumed.

The cumulative result of these assumptions is a range of additional pumping power from a minimum of about 0.3% to a maximum of approximately 1.1% of plant output or 3 to 11 MW for a 1,000 MW plant.

Fan power

Similar assumptions can be used to estimate the amount of fan power required. The tower design choice of the number of cells in the cooling tower per unit of circulating water flow varies with a number of factors including make-up water quality, site climatological characteristics and the space available to place the tower. Typical ranges of circulating water flow, water loading per cell and fan horsepower are tabulated in Table 7-2.

Table 7-2: Range of fan power estimating parameters

Typical range	Circulating water flow (gpm/MW)	Cell loading (gpm/cell)	Plant Output per Cell (MW/cell)	Fan Power per Cell (HP/cell)
Minimum	400	20,000	50.0	125
Intermediate	600	15,000	25.0	175
Maximum	800	10,000	12.5	225

These ranges result in fan power requirements from a minimum of 0.21% to 1.5% of plant power which amounts to 2.1 MW to 15 MW for a 1,000 MW plant. However, the combination of a low power fan with high cell water loadings and vice versa is unlikely so the mid-range estimate (intermediate fan power with intermediate water loading) of 0.6% or 6 MW for a 1,000 MW plant is reasonable.

The sum of the additional operating power required is, therefore, estimated to range from about 0.85 to 1.15% of plant output which amounts to 8.5 MW to 11.5 MW for a 1,000 MW plant.

Heat rate penalty

Conversion of a once-through cooling system to a closed-cycle cooling system using a wet cooling tower frequently results in an increase in the achievable turbine backpressure for most of the year and a corresponding loss of plant efficiency and output. In most circumstances, this loss is greatest during the hottest period of the year at precisely the time that the power requirement of the electrical network is at its peak.

A proper determination of the heat rate penalty requires a calculation of the plant output throughout the year on both the original once-through cooling system and the retrofitted closed-cycle system. This begins with a calculation of the condensing pressure as a function of the source water temperature in the case of once-through cooling and ambient wet bulb temperature in the case of the closed-cycle system. It then remains to assess the effect on plant efficiency and output as a function of the condensing pressure and to determine the difference in plant performance both on an annual average basis and during the hottest period of the year.

The following paragraphs outline the computational procedures involved in each step of the analysis and present the results of selected examples which are intended to cover the range of conditions encountered across the family of Phase II plant sites.

Determination of condensing pressure

The condensing pressure is determined by the condensing temperature maintained by the cooling system. The condensing temperature is given by the cold water inlet temperature to the condenser plus the temperature rise across the condenser ("range") plus the difference between the condenser hot water exit temperature and the condensing temperature (terminal temperature difference or "TTD"). Therefore, the condensing temperature in a once-through cooling system is given by

Once-through cooling: T_{cond} (°F) = T_{source} + Range + TTD

as shown schematically in Figure 7-1a. For a once-through cooling system, the cold water inlet temperature is the source water temperature (T_{source}) available from the natural waterbody.

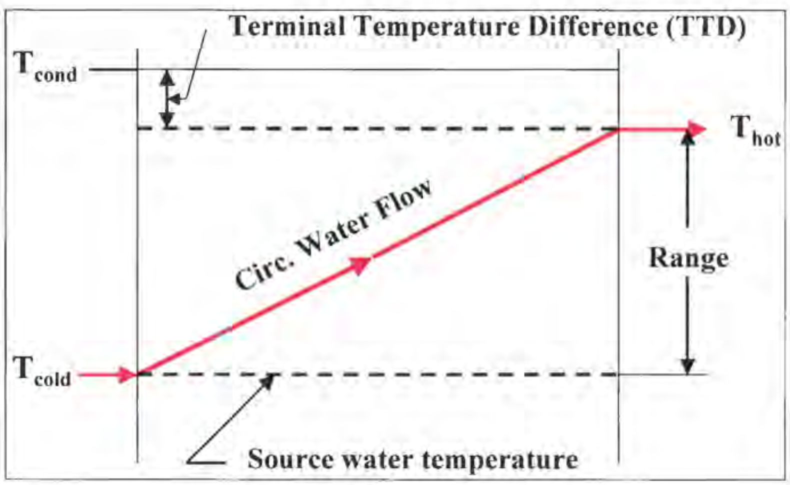


Figure 7-1a: Once-through cooling operating configuration

For a closed cycle cooling system, the cold water temperature is the cooling tower cold water exit temperature given by the ambient wet bulb temperature ($T_{amb\ wb}$) plus the difference between the ambient wet bulb and the tower cold water temperature or the tower "approach" as shown in Figure 7-1b.

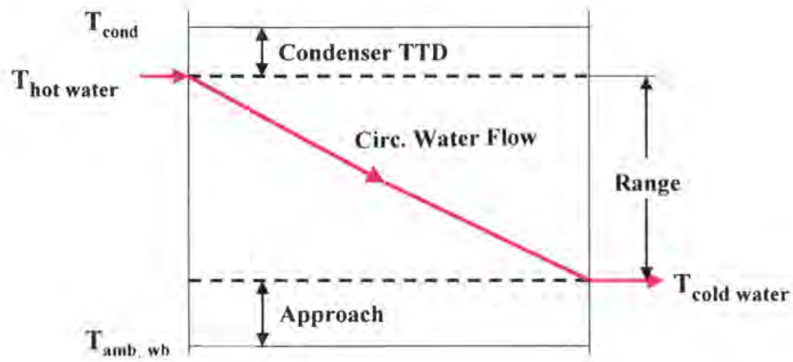


Figure 7-1b: Closed-cycle cooling operating configuration

Therefore, the condensing temperature in a closed-cycle cooling system with a wet cooling tower is given by:

$$\text{Closed-cycle cooling:}\quad T_{cond}\,(^{o}F) = T_{amb\ wb} + \text{Approach} + \text{Range} + \text{TTD}$$

The condensing pressure in each case is then given by the standard steam saturation equation where p_{sat} is expressed in inHga and T_{sat} in °F.

$$p_{sat} = 0.0000000260 * T_{sat}^{4} - 0.00000492 * T_{sat}^{3} + 0.000667 * T_{sat}^{2} - 0.0317 * T_{sat} + 0.754$$

For the usual approach to retrofit where the circulating water flow rate and the condenser are left unchanged, the range and the TTD are the same for both the original and the retrofitted systems. Therefore, the difference in the condensing pressures is determined by the difference between the source water temperature and the ambient wet bulb plus the tower approach temperature.

$$T_{cond/closed\text{-}cycle} - T_{cond/once\text{-}through} = T_{amb,wb} + \text{Approach} - T_{source}$$

Once-through cooling---source water temperature

The average level and yearly variation in natural water body temperatures depends on the waterbody type and size, on the location of the cooling water intake structure and the region of the country. Consistently cold water is obtained from larger water bodies such as oceans and larger lakes and rivers in the northern parts of the country. Small rivers, small lakes and reservoirs and some inlets, bays and estuaries typically have higher average temperatures and high summertime temperatures. Exceptions exist. In the large water bodies, colder water is more consistently obtained with offshore, submerged intakes. Shoreline surface intakes, even at ocean-side plants, and particularly in protected bays or coves off the main ocean itself, can see much higher annual temperatures and significantly higher summertime temperatures. Figure 7-2 displays several examples.

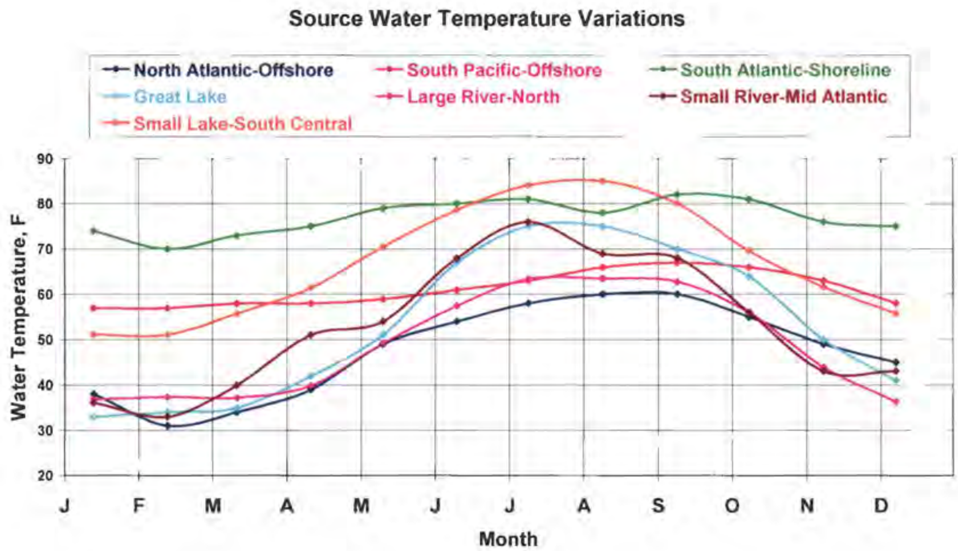


Figure 7-2: Variations in natural waterbody temperatures

Condenser range and TTD

The cooling water temperature rise across the condenser (the "range") is proportional to the condenser heat duty and inversely proportional to the cooling water flow rate. For a nominal plant heat rate of 10,000 Btu/kWh, the condenser heat load is around 5,000 Btu/kWh for a fossil plant and 6,500 Btu/kWh for a nuclear plant. As displayed in Figure 3-2, circulating water flow rates fall mostly in the range of 400 to 800 gpm/MW. This results in typical condenser temperature rises from approximately 12 to 25°F for fossil plants and 15 to 30°F for nuclear plants.

Most condenser design TTD's are in the range of 7 to 12°F although in some instances, where a reliable year-round supply of cold water was assured, smaller condensers with higher TTD's were specified. Rare examples with TTD's as high as 25 to 30°F were reported. For purposes of the following examples, the sum of the condenser temperature rise and the TTD will be assumed to range from approximately 20°F (~12°F + 7 °F) to 40°F (~ 30°F + 12°F).

For mid-range values of a 20°F range and a 10°F TTD, the corresponding condensing temperatures and condensing pressures for the source water sites shown in Figure 7-2 are shown in Figures 7-3a and 7-3b.

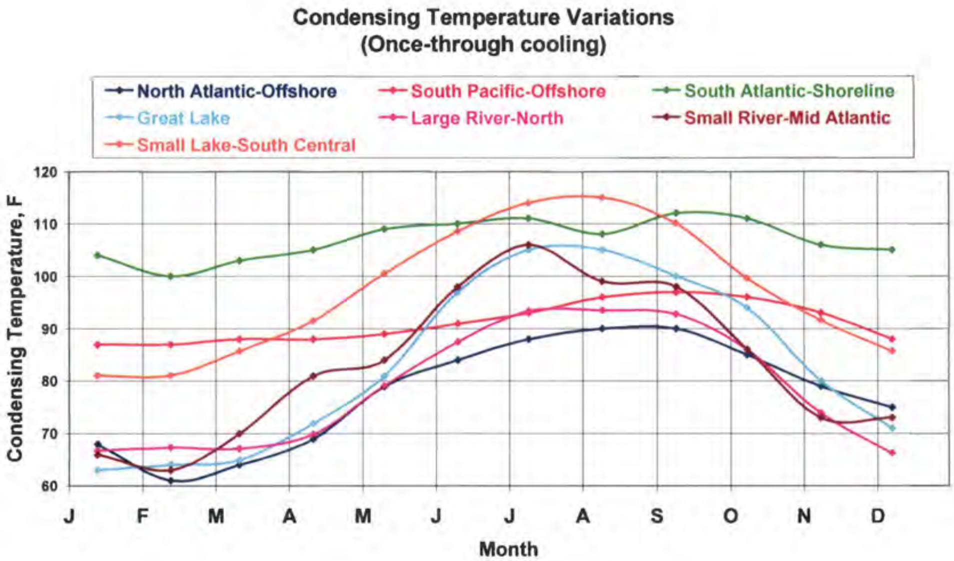


Figure 7-3a: Variations in condensing temperatures for once-through cooled systems

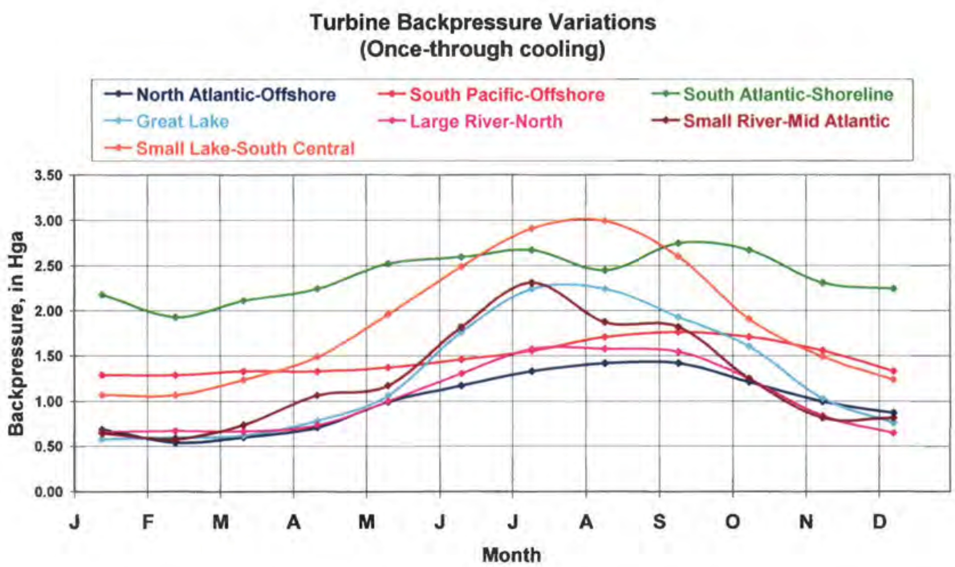


Figure 7-3b: Variations in condensing pressures for once-through cooled systems

The range of operating turbine backpressure estimated for sites in each of the seven regions representing very different water bodies and climatic regions is from 0.5 to 3.0 in Hga. This corresponds precisely to the range of reported operating conditions from plants providing operating data for the study. An important feature of the result is that for many of these sites, there is a substantial variation in backpressure over the course of the year. The backpressures for the "Great Lakes" and the "Small River—Mid-Atlantic" sites vary from 0.5 in Hga in the winter to over 2.5 in Hga in the summer. The Small Lake-South Central site varies from 1.0 in Hga to 3.0 in Hga from winter to summer. As will be seen later in the analysis, this variation is important in evaluating the penalty associated with closed-cycle cooling retrofits.

Closed-cycle cooling—ambient wet bulb temperatures

As in the case of natural waterbody temperatures, the level and variability of ambient wet bulb temperature is a function not only of climatic region but also of very local conditions in the vicinity of the plant. Figure 7-4 displays the wet bulb temperature plots for the same seven sites. Where possible, plant data were used. When plant data were not available, public sources of meteorological data were used, typically taken at neighboring airports. (7-1, 7-2)

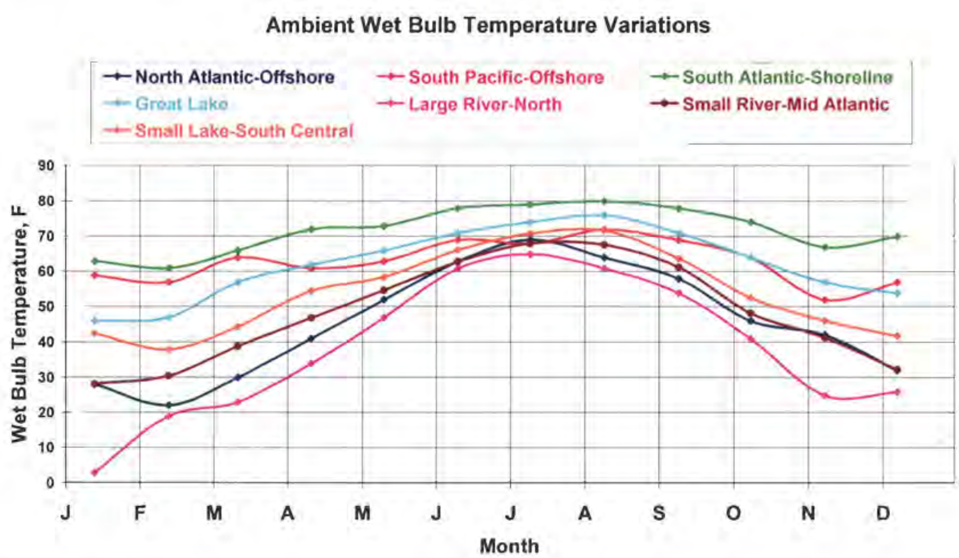


Figure 7-4: Variations in Ambient Wet Bulb Temperature

Local variations in wet bulb temperatures are usually grater than variations in local waterbody temperature. However, as will be seen, these variations do not affect changes in the condensing temperature as strongly as do source water temperature changes in once-through cooling systems.

Cooling tower approach temperature

The effectiveness of a tower in cooling water to a temperature close to the ambient wet bulb temperature is a function of cooling tower size, water-to-air flow ratio (L/G) and fill characteristics. As discussed previously, retrofits are assumed for purposes of this study to use mechanical-draft, counterflow cooling towers. Typical design approaches for these towers range from about 6 to 12 °F with the lower approaches typically chosen in hotter, more humid regions and the higher approaches at cooler, drier sites. The following example will use a mid-range design approach of 9 °F. The greatest likely error in the condensing temperature as a result of this generalization is +/- 3 °F which will not affect the backpressure significantly. Therefore, the error in the estimated efficiency penalty will be small.

However, the approach at off-design operation is not the same as the approach at design conditions. The tower is normally designed for a "design approach" at the "0.4% wet bulb" at the site; that is, the wet bulb temperature which will be exceeded for only 0.4% of the hours of the year. Therefore, for nearly the entire year, the tower will be operating at an ambient wet bulb temperature well below the design value. As the ambient wet bulb decreases, the tower approach increases because the vapor pressure of water which drives the evaporation process decreases at lower temperatures. Therefore, for a given tower with a fixed fan power, water-to-air flow ratio (L/G), the cold water temperature leaving the tower will decrease more slowly than the ambient wet bulb. While the precise factor varies with tower design, a reasonable estimate is that the cold water temperature decreases by 0.5 °F for each 1 °F drop in wet bulb. The following calculations employ this approximation.

As noted above, the condenser range and TTD are unchanged from the original once-through system and estimates of condensing temperature and condensing pressure will assume the sum of range plus TTD to be 30 °F as above.

Figures 7-5a and 7-5b show the estimated range of condensing temperature and pressure for the same seven sites as previously displayed for once-through cooling.

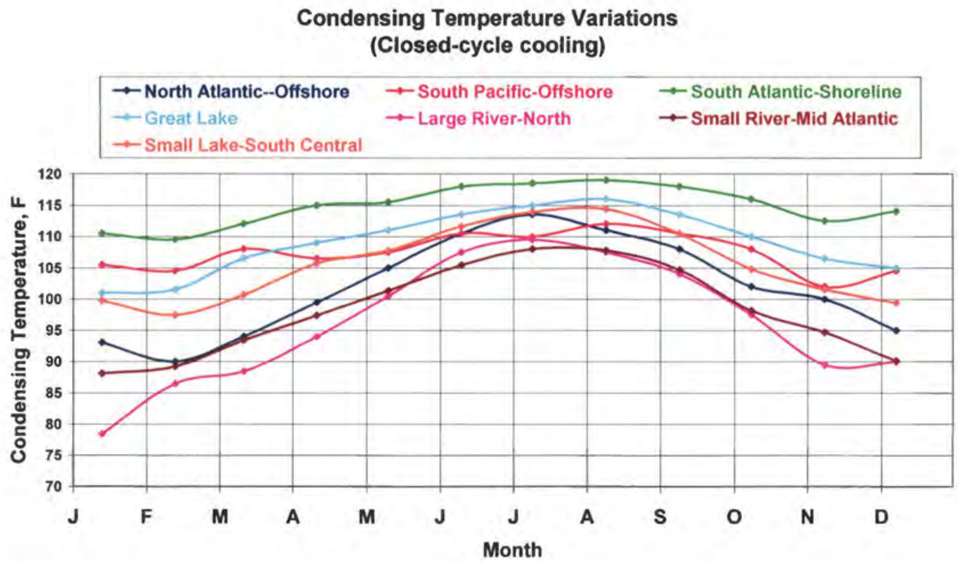


Figure 7-5a: Variations in condensing temperatures for closed-cycle cooling systems

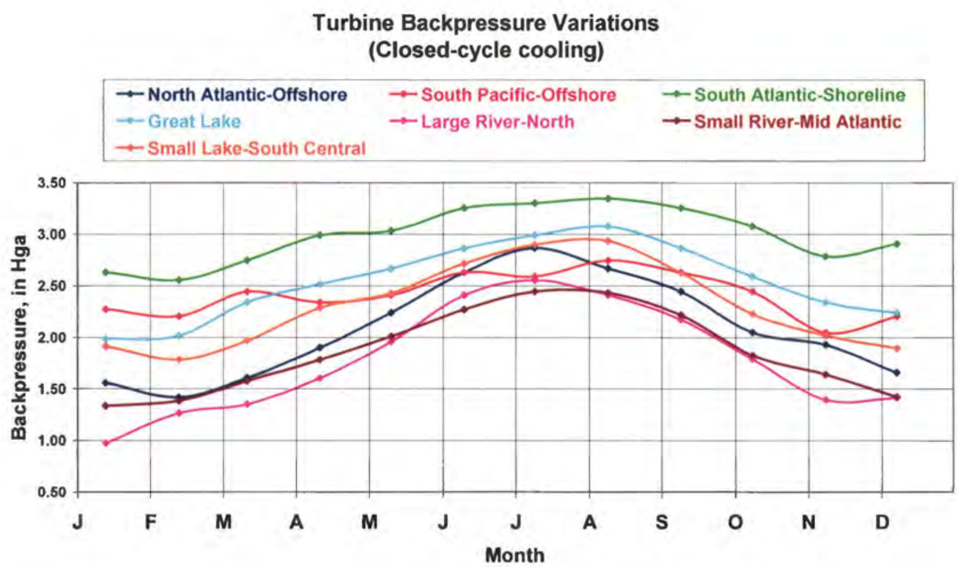


Figure 7-5b: Variations in condensing pressures for closed-cycle cooling systems

The difference in cooling system performance can be quantified by the difference in the turbine exhaust pressures achieved by the two systems. Figure 7-6 displays the difference in the backpressures plotted in Figures 7-4 and 7-5 (expressed as closed-cycle backpressure minus once-through backpressure) for each of the seven sites over the course of a year.

Several items are noteworthy.

- For most of the time at most of the sites the backpressure with closed-cycle cooling exceeds that with once-through cooling by 0.5 to 1.0 in Hga.
- In two instances, the "Great Lakes" site in the Spring and the "North Atlantic—Offshore" in the Summer, the difference exceeds 1.5 to 2.0 in Hga.
- In once instance, "Small Lake—South Central" there is a brief period during which the closed-cycle backpressure is less than the backpressure achieved with once-through cooling.

The values plotted in Figures 7-5a, -5b and –6 are based on monthly average temperatures. Tables 7-3 and 7-4 provide the condensing temperatures and backpressure differences for the annual maximum ("hot day") condition (7-3) and the annual average conditions (7-4). It is interesting to note that, contrary to widely held belief, the performance penalty on the "hot day" is not always greater than the annual average. While it is at Sites 1 and 5, at all other sites the hot day penalty is approximately the same as, and in some cases significantly less than, the annual average penalty.

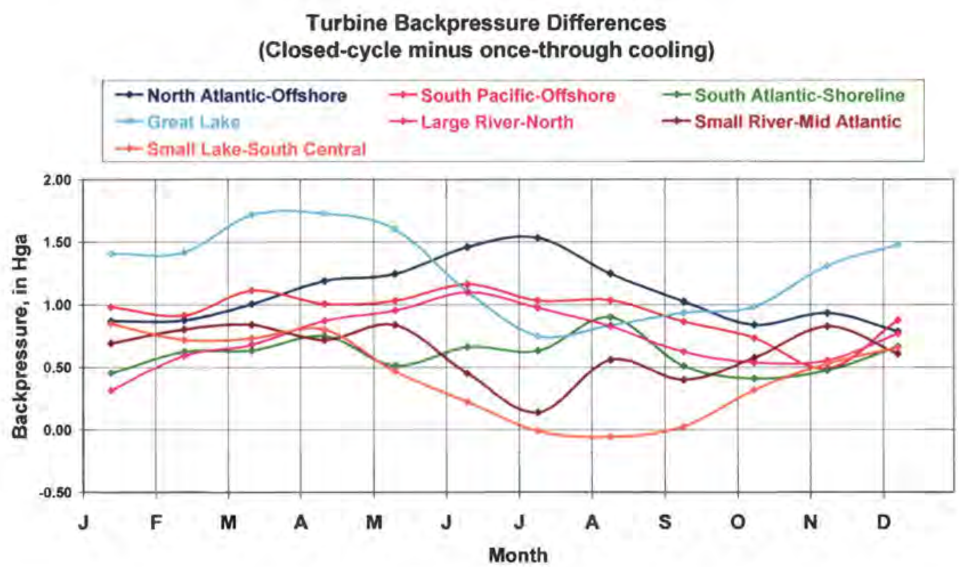


Figure 7-6: Backpressure differences---closed-cycle minus once-through cooling

Table 7-3: Summary of differences at "hot day" conditions

Site	1	2	3	4	5	6	7
$T_{source\ max}$, F	67	70	86	83	69	80	89
$T_{amb\ wb\ max}$, F	75	72	82	78	76	78	79
$T_{cond\ OTC}$, F	97	100	116	113	99	110	119
$T_{cond\ Cl\ Cyc}$, F	114	111	121	117	115	117	118
$p_{cond\ OTC}$, in Hga	1.77	1.93	3.08	2.83	1.88	2.60	3.35
$p_{cond\ Cl\ Cyc}$, in Hga	2.91	2.67	3.54	3.17	2.99	3.17	3.26
Difference	1.15	0.74	0.46	0.34	1.12	0.57	-0.09

Table 7-4: Summary of differences at annual average conditions

Site	1	2	3	4	5	6	7
$T_{source\ ave}$, F	48	61	77	53	49	53	67
$T_{amb\ wb\ ave}$, F	46	63	72	62	38	48	54
$T_{cond\ OTC}$, F	78	91	107	83	79	83	97
$T_{cond\ Cl\ Cyc}$, F	103	108	115	110	98	99	106
$p_{cond\ OTC}$, in Hga	0.96	1.47	2.38	1.14	0.99	1.14	1.77
$p_{cond\ Cl\ Cyc}$, in Hga	2.08	2.42	2.99	2.55	1.78	1.87	2.31
Difference	1.13	0.95	0.61	1.41	0.79	0.72	0.55

Effect of backpressure on performance

It remains to estimate how the increases in turbine backpressure affect plant efficiency and output. General information was obtained from a standard reference handbook (7-13)
and is summarized in Table 7-5 and plotted in Figures 7-7 through 7-10. Table 7-5 groups a range of turbine sizes by steam throttle pressure. The deleterious effect of increased exhaust pressure on turbine performance is related to losses in the last stages of the turbine. The percent loss at an exhaust pressure of 5 in Hga, for turbines designed for 1.5 in Hga shows an inverse linear relationship to exhaust plane energy flux expressed as kW/ft^2. This is shown in Figure 7-7.

The variation in lost turbine output is plotted for 12 turbine designs in Figure 7-8. The results are reasonable bracketed by the lines shown. In general, larger turbines with higher throttle pressures exhibit less loss with increasing exhaust pressure than do smaller, lower throttle pressure designs. The range of lost output for an exhaust pressure of 3.5 in Hga (a 2 in Hga increase over the design pressure of 1.5 in Hga) is from 1.5 to 4.%.

Nominal rating	Steam conditions			Turbine compound, 3,600 rpm last-stage buckets				Boiler feed pump drive	Net heat rate, Btu/kWh at rated load and steam conditons and at exhaust pressure, in Hga					% increse above 1.5 in Hga in net heat rate at rated load and and at exhaust pressure				
MW @ 1.5 in Hga	Throttle pressure	Temp	Reheat Temp	No. of rows	Length	Exhaust area	Approx kW/ft2											
MW	psig	F	F		in	ft2	kW/ft2		1.5	2	3	4	5	1.5	2	3	4	5
150	1,800	1,000	1,000	2	26	82	1,829	**Motor**	8,010	8,060	8,230	8,440	8,630	0	0.006	0.027	0.054	0.077
235	1,800	1,000	1,000	2	26	82	2,866	**Motor**	8,240	8,240	8,290	8,380	8,500	0	0.000	0.006	0.017	0.032
250	1,800	1,000	1,000	2	30	111	2,252	**Motor**	8,080	8,100	8,220	8,400	8,620	0	0.002	0.017	0.040	0.067
250	1,800	1,000	1,000	2	30	111	2,252	Turbine	8,030	8,060	8,200	8,390	8,610	0	0.004	0.021	0.045	0.072
250	2,400	1,000	1,000	2	30	111	2,252	Turbine	7,850	7,890	8,030	8,240	8,450	0	0.005	0.023	0.050	0.076
500	2,400	1,000	1,000	4	30	222	2,252	Turbine	7,790	7,830	7,970	8,170	8,370	0	0.005	0.023	0.049	0.074
700	2,400	1,000	1,000	4	33.5	264	2,652	Turbine	7,860	7,870	7,970	8,130	8,320	0	0.001	0.014	0.034	0.059
1000	2,400	1,000	1,000	6	30	334	2,994	Turbine	7,920	7,930	8,000	8,100	8,250	0	0.001	0.010	0.023	0.042
500	3.,500	1,000	1,000	4	30	222	2,252	Turbine	7,620	7,660	7,820	8,030	8,220	0	0.005	0.026	0.054	0.079
700	3.,501	1,000	1,000	4	33.5	264	2,652	Turbine	7,670	7,690	7,810	7,980	8,170	0	0.003	0.018	0.040	0.065
1000	3.,502	1,000	1,000	6	30	334	2,994	Turbine	7,710	7,730	7,810	7,940	8,090	0	0.003	0.013	0.030	0.049
1100	3.,503	1,000	1,000	6	33.5	397	2,771	Turbine	7,680	7,700	7,810	7,960	8,140	0	0.003	0.017	0.036	0.060

Table 7- 5: Turbine performance characteristics (Summarized from Ref. 7-

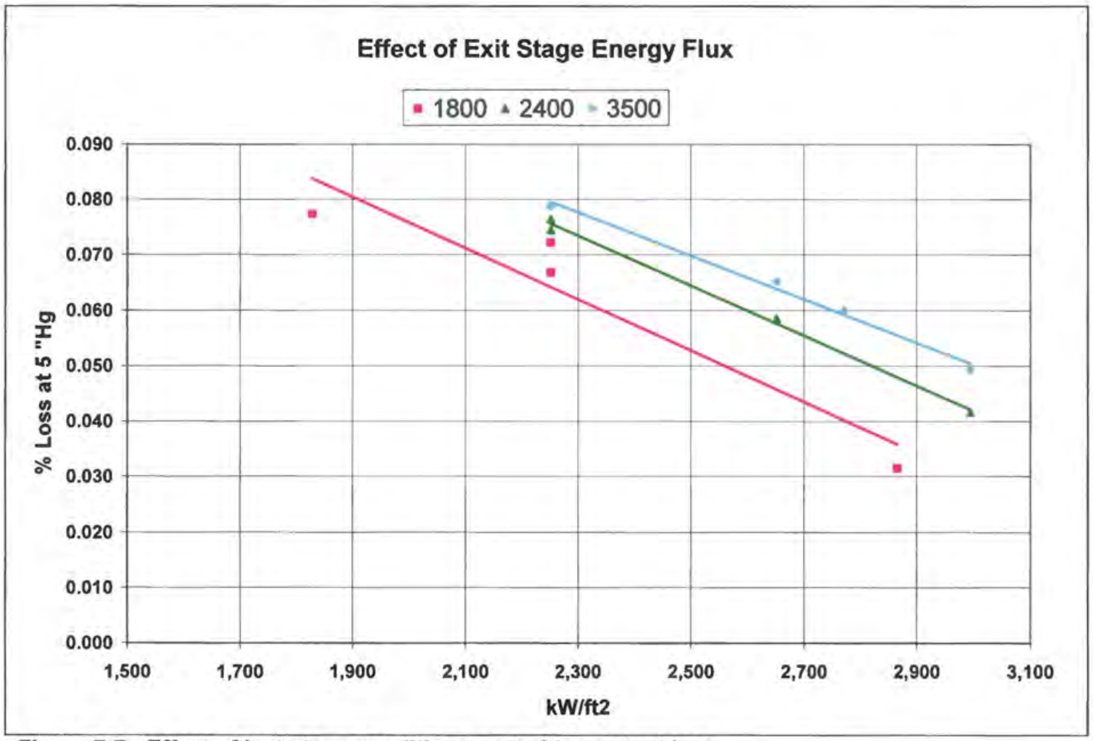


Figure 7-7: Effect of last stage conditions on turbine output loss

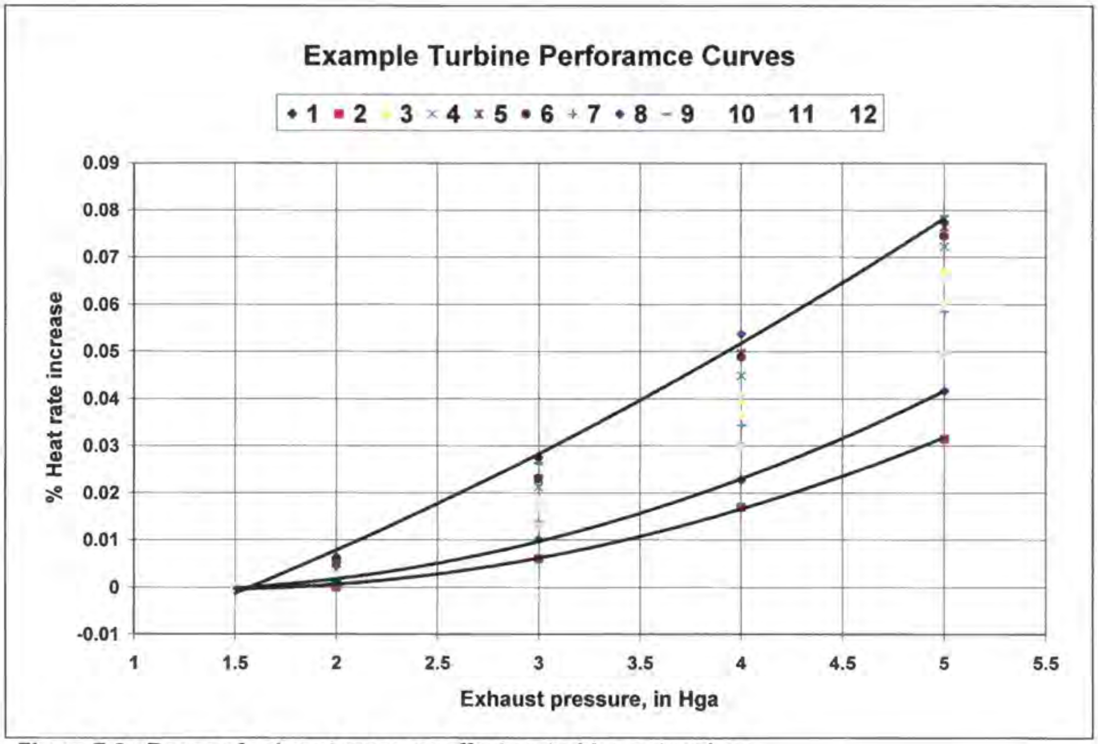


Figure 7-8: Range of exhaust pressure effect on turbine output loss

Figure 7-9 shows similar results for "textbook" examples for "typical" coal and nuclear plant turbines. The nuclear turbines have a much lower throttle pressure and show significantly higher lost output with increasing exhaust pressure.

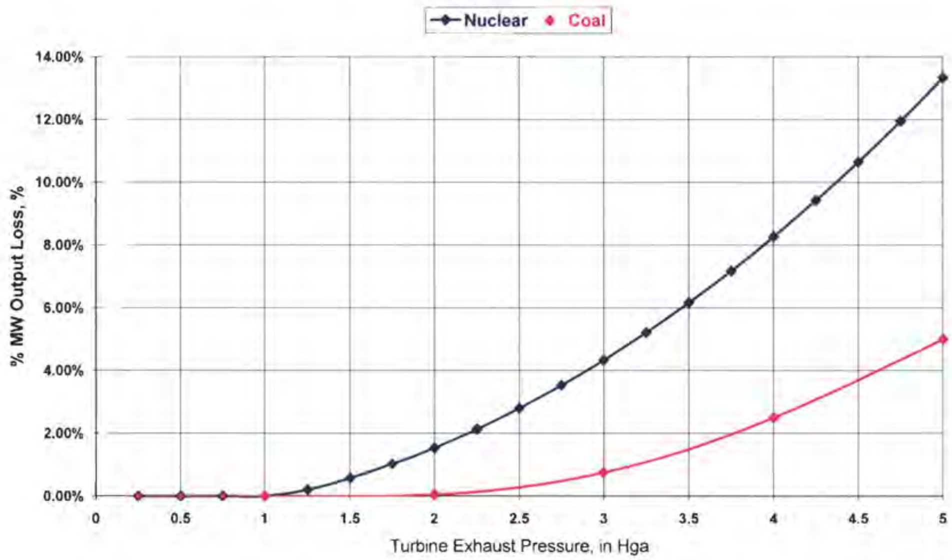


Figure 7-9: Heat Rate (Plant Performance vs. Turbine Backpressure) Curve

Additional consideration is the variation in sensitivity to backpressure with turbine steam flow or plant load. Figure 7-10 shows the much higher lost output expressed as "% Change in Heat Rate" for a range of steam flows with full load operation showing the least effect of increasing backpressure.

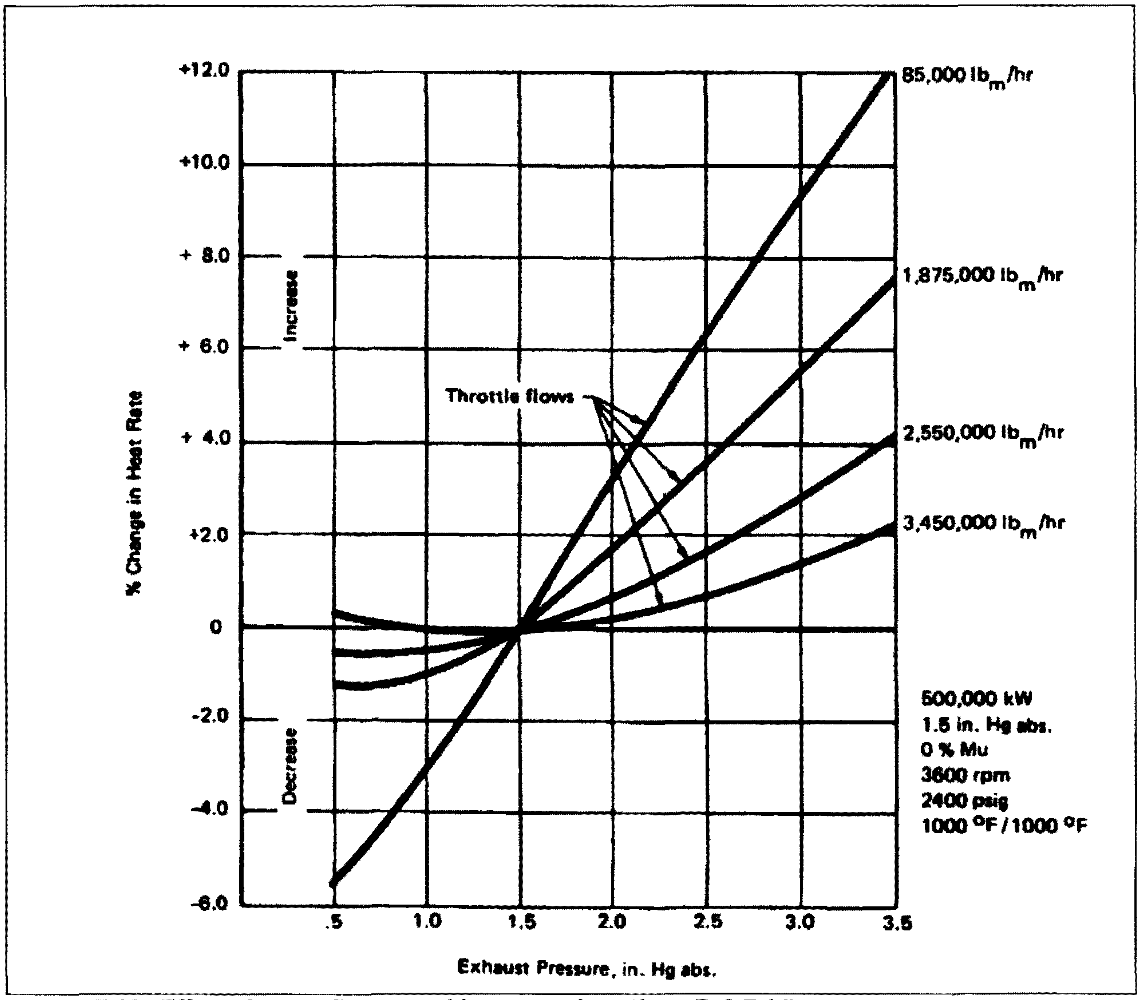


Figure 7-10: Effect of steam flow on turbine output loss (from Ref. 7-14)

Finally, the questionnaires distributed to Phase II plants (See Appendix C) included a request for turbine design operating conditions and the reduction in capacity with elevated backpressures. (See Worksheet 12; "Unit Cooling System Data") While most respondents omitted this information, approximately 40 plants representing over 80 units did provide it. The responses are listed in Table 7-6.

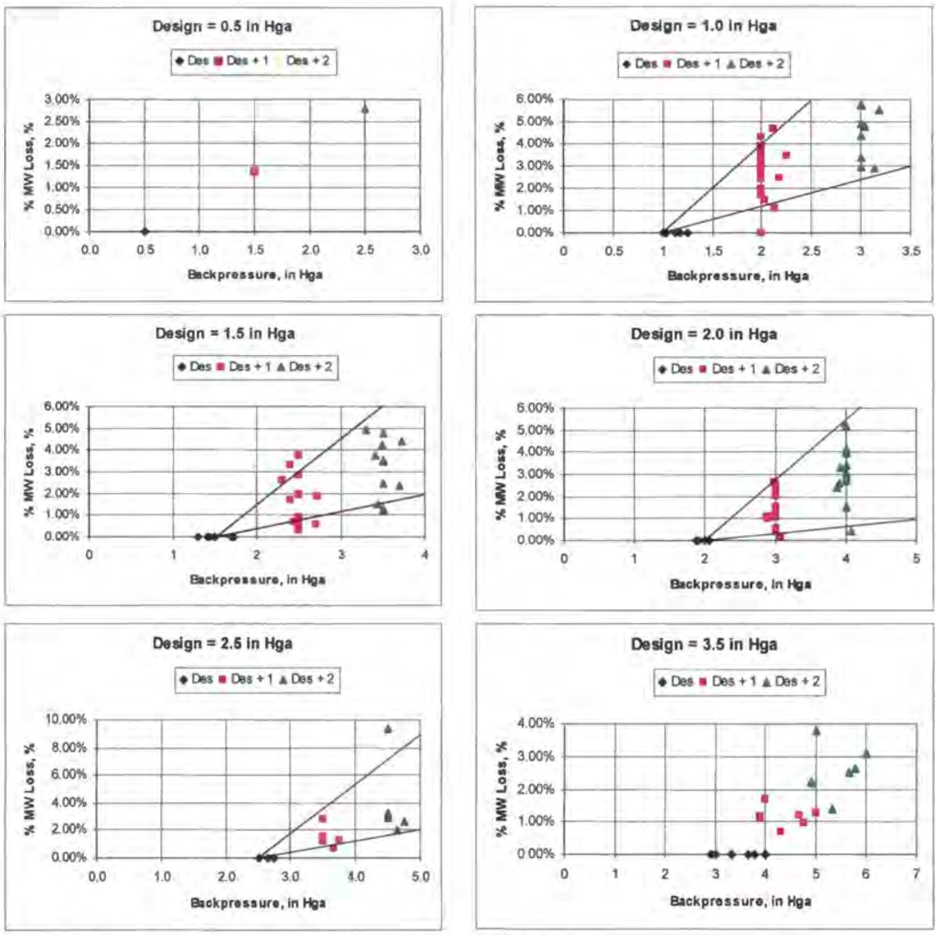
The data were divided into 6 groups by design backpressure from 0.5 to 3.5 in Hga and the loss in output, expressed as a percent of design capacity, was plotted vs. turbine backpressure in Figures 7-11a through 7-11f. As seen in the plots, there is little consistency to the data.

F510/1	Coal	0.5	1.5	2.5	324	320	315	0.00%	1.36%	2.78%
F510/2	Coal	0.5	1.5	2.5	324	320	315	0.00%	1.36%	2.78%
F277/7	Coal	1	2.0	3.0	238	234	230	0.00%	1.68%	3.36%
F277/8	Coal	1	2.0	3.0	348	339	331	0.00%	2.59%	4.89%
F296/7	Coal	1	2.0	3.0	102	102	99	0.00%	0.00%	2.94%
F303/1	Coal	1.0	2.0	3.0	77	74	69	0.00%	3.90%	10.39%
F339/1	Coal	1.0	2.0	3.0	7,263	7,437	7,684	0.00%	2.40%	5.80%
F378/1	Coal	1.0	2.0	3.0	170	162	158	0.00%	4.33%	6.81%
F382/19	Coal	1.0	2.0	3.0	348	338	328	0.00%	2.87%	5.75%
F451/1	Coal	1.0	2.0	3.0	175	169	164	0.00%	3.49%	6.51%
F451/2	Coal	1	2.0	3.0	177	170	164	0.00%	3.73%	7.40%
F451/3	Coal	1	2.0	3.0	291	282	272	0.00%	3.16%	6.46%
F451/4	Coal	1	2.0	3.0	577	566	552	0.00%	1.99%	4.35%
F505/1	Coal	1.0	2.0	3.0	136	134	130	0.00%	1.47%	4.78%
F505/2	Coal	1.0	2.0	3.0	136	134	130	0.00%	1.47%	4.78%
F226/6	Coal	1.12	2.1	3.1	341	325		0.00%	4.69%	
F505/3	Coal	1.13	2.1	3.1	182	180	177	0.00%	1.10%	2.88%
F505/4	Coal	1.13	2.1	3.1	182	180	177	0.00%	1.10%	2.88%
F546/7	Coal	1.18	2.2	3.2	359	350	339	0.00%	2.45%	5.52%
F378/2	Coal	1.25	2.3	3.3	250	241	235	0.00%	3.49%	6.08%
F546/8	Coal	1.3	2.3	3.3	384	374	365	0.00%	2.60%	4.95%
Fos 6/1	Coal	1.4	2.4	3.4	260	256	250	0.00%	1.69%	3.77%
Fos 6/2	Coal	1.4	2.4	3.4	360	348	338	0.00%	3.31%	6.17%
Fos 1/3	Coal	1.44	2.4	3.4	148	147	146	0.00%	0.68%	1.49%
F241/1	Coal	1.49	2.5	3.5	na	na	na	0%	2%	4.25%
F241/2	Coal	1.49	2.5	3.5	na	na	na	0%	2%	4.25%
F303/2	Coal	1.5	2.5	3.5	80	77	72	0.00%	3.75%	10.00%
F303/3	Coal	1.5	2.5	3.5	80	77	72	0.00%	3.75%	10.00%
F306/3	Coal	1.5	2.5	3.5	105	102	100	0.00%	2.86%	4.76%
F383/1	Coal	1.5	2.5	3.5	228,860	228,144	225,868	0.00%	0.31%	1.31%
F383/2	Coal	1.5	2.5	3.5	468,097	458,974	451,501	0.00%	1.95%	3.55%
F481/1	Coal	1.5	2.5	3.5	808	804	788	0.00%	0.50%	2.49%
F481/2	Coal	1.5	2.5	3.5	833	826	804	0.00%	0.90%	3.48%
F481/3	Coal	1.5	2.5	3.5	833	826	804	0.00%	0.90%	3.48%
F481/4	Coal	1.5	2.5	3.5	813	809	793	0.00%	0.50%	2.49%
F251/8	Coal	1.72	2.7	3.7	na	na	na	0.00%	1.90%	4.40%
Fos 1/2	Coal	1.87	2.9	3.9	82	81	80	0.00%	1.10%	2.44%
Fos 1/1	Coal	1.9	2.9	3.9	81	80	78	0.00%	0.99%	2.61%
Fos 6/3	Coal	1.91	2.9	3.9	835	825	807	0.00%	1.15%	3.34%
F181/1	Coal	2.0	3.0	4.0	195	192	189	0.00%	1.54%	3.08%
F251/7	Coal	2	3.0	4.0	na	na	na	0	1.30%	4.20%
F268/1	Coal	2.0	3.0	4.0	656	642	630	0.00%	2.13%	3.96%
F271/1	Coal	2.0	3.0	4.0	7,811	8,006	8,123	0.00%	2.50%	3.99%
F407/1	Coal	2.0	3.0	4.0	395,703	391,011	384,178	0.00%	1.19%	2.91%
F407/2	Coal	2.0	3.0	4.0	526,160	523,022	517,874	0.00%	0.60%	1.57%
F211/1	Coal	2.1	3.1	4.1	115	115	115	0.00%	0.17%	0.43%
F211/2	Coal	2.1	3.1	4.1	115	115	115	0.00%	0.17%	0.43%
F248/1	Coal	2.5	3.5	4.5	535	520	485	0.00%	2.80%	9.35%
F248/2	Coal	2.5	3.5	4.5	535	520	485	0.00%	2.80%	9.35%
F380/1	Coal	2.7	3.7	4.7	190,908	189,581	186,981	0.00%	0.70%	2.06%
F380/2	Coal	2.75	3.8	4.8	185,156	182,780	180,288	0.00%	1.28%	2.63%
F318/5	Coal	2.9	3.9	4.9	75,000	74,169	73,318	0.00%	1.11%	2.24%
F318/6	Coal	2.9	3.9	4.9	162,000	160,137	158,436	0.00%	1.15%	2.20%
F267/2	Coal	3	4.0	5.0	487	479	469	0.00%	1.70%	3.80%
F425/3	Coal	3.66	4.7	5.7	685,668	677,538	668,292	0.00%	1.19%	2.53%
F425/2	Coal	3.77	4.8	5.8	684,950	678,168	666,943	0.00%	0.99%	2.63%
F425/1	Coal	4.0	5.0	6.0	376,791	371,956	365,108	0.00%	1.28%	3.10%

Table 7-6: Plant data on effect of backpressure on performance

Plant/Unit ID	Fuel	Turbine Backpressure, in Hga			Performance Loss (expressed in MW, kW or Btu/kWh)			% MW Loss		
		Design	Design + 1	Design + 2	MW des	MWdes1	MWdes2	Des	Des + 1	Des + 2
N233	Nucl	1.7	2.7	3.7	1,296	1,288	1,265	0.00%	0.61%	2.37%
N513	Nucl	2.0	3.0	4.0	790	769	748	0.00%	2.66%	5.32%
N100	Nucl	3.31	4.3	5.3	992	985	978	0.00%	0.71%	1.41%
N100	Nucl	3.31	4.3	5.3	992	985	978	0.00%	0.71%	1.41%
F306/1	Oil/gas	1.5	2.5	3.5	239	237	236	0.00%	0.84%	1.26%
F306/2	Oil/gas	1.5	2.5	3.5	242	240	239	0.00%	0.83%	1.24%
F280/1	Oil/gas	2.0	3.0	4.0	131,797	129,086	126,363	0.00%	2.06%	4.12%
F280/2	Oil/gas	2.0	3.0	4.0	132,320	129,598	126,865	0.00%	2.06%	4.12%
F280/3	Oil/gas	2.0	3.0	4.0	213,773	211,447	207,950	0.00%	1.09%	2.72%
F281/1	Oil/gas	2	3.0	4.0	277,000	273,925	267,444	0.00%	1.11%	3.45%
F281/2	Oil/gas	2	3.0	4.0	277,000	273,925	267,444	0.00%	1.11%	3.45%
F347/1	Oil/gas	2.0	3.0	4.0	37,565	36,649	35,607	0.00%	2.44%	5.21%
F347/2	Oil/gas	2.0	3.0	4.0	37,323	36,413	35,377	0.00%	2.44%	5.21%
F347/3	Oil/gas	2.0	3.0	4.0	83,555	81,517	79,199	0.00%	2.44%	5.21%
F450/1	Oil/gas	2.0	3.0	4.0	527,911	525,285	520,109	0.00%	0.50%	1.48%
F450/2	Oil/gas	2.0	3.0	4.0	527,911	525,285	520,109	0.00%	0.50%	1.48%
F194/1	Oil/gas	2.5	3.5	4.5	156,000	153,863	151,492	0.00%	1.37%	2.89%
F394/1	Oil/gas	2.5	3.5	4.5	135,516	133,348	131,112	0.00%	1.60%	3.25%
F394/2	Oil/gas	2.5	3.5	4.5	137,002	134,834	132,598	0.00%	1.58%	3.21%
F449/1	Oil/gas	2.5	3.5	4.5	225,000	221,625	218,475	0.00%	1.50%	2.90%
F449/2	Oil/gas	2.5	3.5	4.5	225,000	221,625	218,475	0.00%	1.50%	2.90%
F449/3	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%
F449/4	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%
F537/1	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%
F537/2	Oil/gas	2.5	3.5	4.5	402,000	397,176	389,337	0.00%	1.20%	3.15%

Table 7-6 (cont.): Plant data on effect of backpressure on performance



Figures 7-11a through -11f: Performance Loss Data

Attempts to discern relationships with turbine size or age (no other characterizing information was available) were unsuccessful. Therefore, the following approach was adopted to develop estimates of the reduction in turbine performance as a function of increased exhaust pressure.. The data sets for each of the design backpressures were bracketed with linear boundaries representing "high" and "low" coefficients of % loss per in Hga of backpressure increase. The range from all 6 plots gave 3.5% MW loss per in Hga for the maximum effect and 0.3% MW loss per in Hga for the minimum. An intermediate value of 1.9% MW loss per in Hga was inferred from the two extremes.

The coefficients were then applied to the "Hot Day" and "Annual Average" backpressure differences tabulated in Table 7-3 and 7-4. The results for Performance Penalty at hot day and annual average conditions are tabulated in Tables 7-7 and 7-8.

Table 7-7: Turbine Performance Loss at Hot Day Conditions

% Output Loss---"Hot Day" Conditions							
Site	1	2	3	4	5	6	7
Maximum	4.0%	2.6%	1.6%	1.2%	3.9%	2.0%	-0.3%
Intermediate	2.2%	1.4%	0.9%	0.6%	2.1%	1.1%	-0.2%
Minimum	0.34%	0.22%	0.14%	0.10%	0.34%	0.17%	-0.03%

Table 7-8: Turbine Performance Loss at Annual Average Conditions

% Output Loss---Annual Average Conditions							
Site	1	2	3	4	5	6	7
Maximum	4.0%	3.3%	2.2%	4.9%	2.8%	2.5%	1.9%
Intermediate	2.1%	1.8%	1.2%	2.7%	1.5%	1.4%	1.0%
Minimum	0.34%	0.28%	0.18%	0.42%	0.24%	0.22%	0.16%

While the general range of 1.0 to 2.0% annual average penalty at most sites is reasonably consistent with previous estimates (7-4, 7-5), the "hot day" penalties are generally less than had been assumed. This appears to result from the reported annual variation in natural waterbody source water temperature showing significant summertime increases which had perhaps not been accounted for in previous general analyses.

Additionally, the financial impact of a decrease in plant efficiency and peak day output is a complex function of the plant operating profile and capacity factor and the company contractual arrangements with the grid. Precise cost determinations in this area are beyond the scope of this study. However, some general approximation assuming industry average factors can be made as will be discussed in Chapter 8.

For purposes of clarification, two illustrative examples for two distinct climatic zones are presented below.

Lake source in mid-Atlantic state

Figure 7-12 shows the seasonal variation in the temperature of cooling water available from the lake currently used as the source of water for once-through cooling, the ambient wet-bulb temperature and the resulting cold water temperature from the tower.

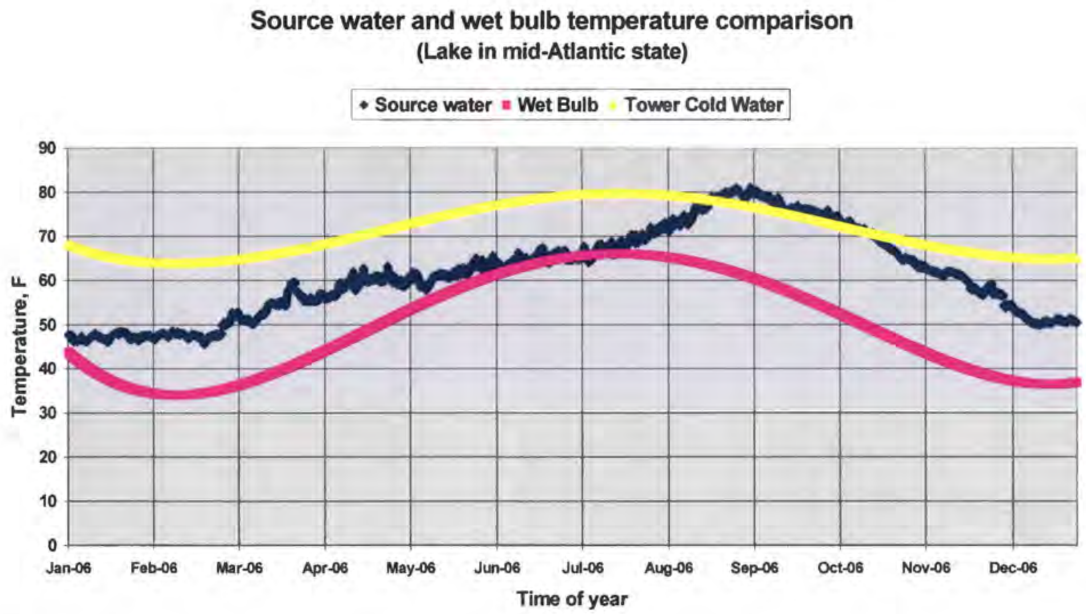


Figure 7-12: Temperature comparisons in mid-Atlantic state with lake water source

Based on the design point of the existing once-through cooling system, the comparative turbine backpressures over the course of the year are shown in Figure 7-13. Note that in both plots the closed cycle curves are smoothed compared to the once-through curves. This is a result of having daily values available for the once-through operation, while having only monthly average values for the closed-cycle conditions which were then approximated with a polynomial curve fit.

In this example, the backpressure with closed-cycle cooling is well above that with once-through cooling for most of the year, but approximately the same for the hottest period. This is a result of the lake water temperature rising to very high levels in the late summer, while the wet-bulb temperature varies more moderately during the same period. In this instance, the closed-cycle system produces a slightly lower backpressure for a brief period. Throughout the year, the average backpressure on closed-cycle cooling is 0.41 in Hga higher than that with once-through cooling with a maximum difference of 0.81 in Hga in early July.

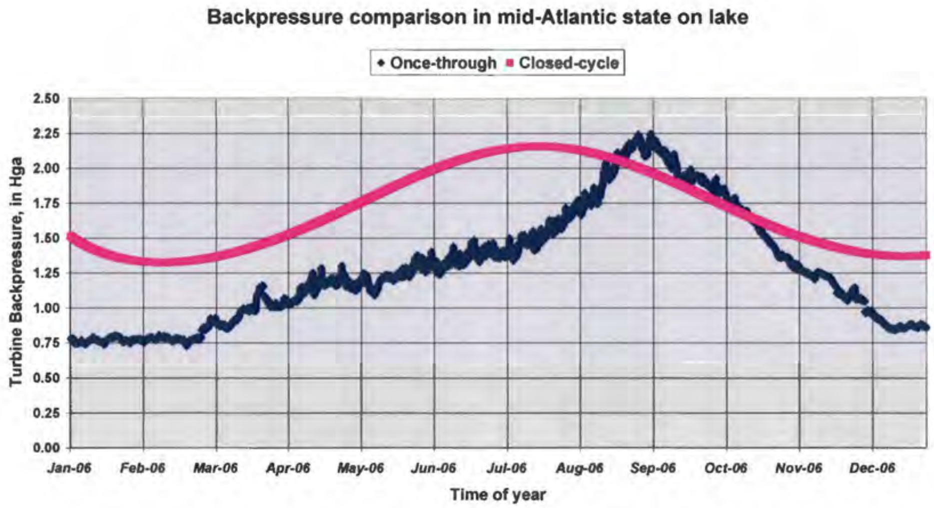


Figure 7-13: Backpressure comparisons in mid-Atlantic state with lake water source

Ocean cooling in the Northeast

Comparable curves are shown for a different set of source water and climatic conditions in Figures 7-14 and 7-15.

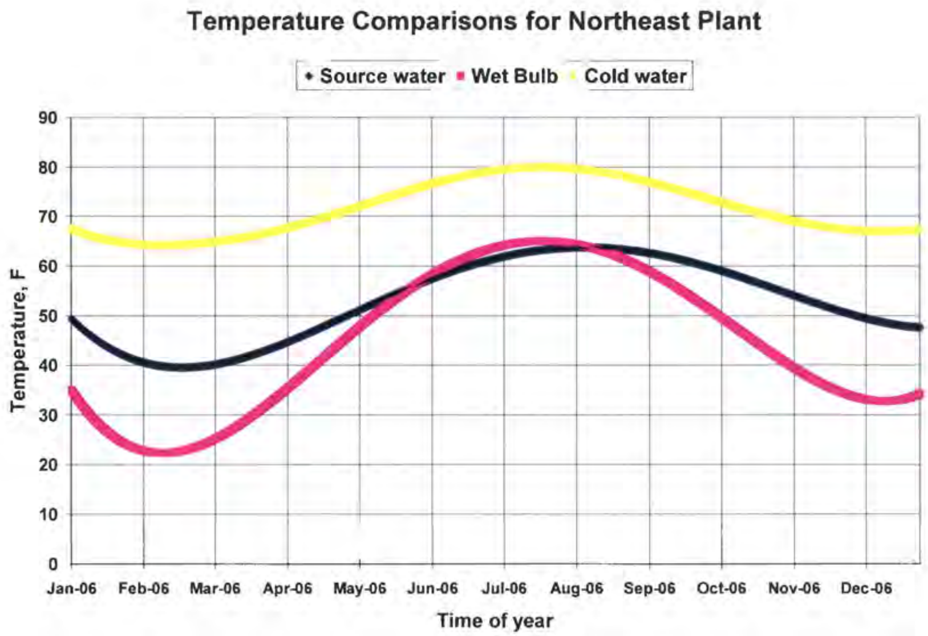


Figure 7-14: Cooling water temperature comparison with ocean cooling in Northeast

In the example shown in Figure 7-14, the backpressure with closed-cycle cooling is well above that with once-through cooling for the entire year. This is a result of the ocean water temperature being consistently low throughout the year with little variation, while the wet-bulb temperature varies over a greater range during the same period. On average throughout the year, the average backpressure on closed-cycle cooling is 1.2 in Hga higher than that with once-through cooling with a maximum difference of 1.4 in Hga in mid-June.

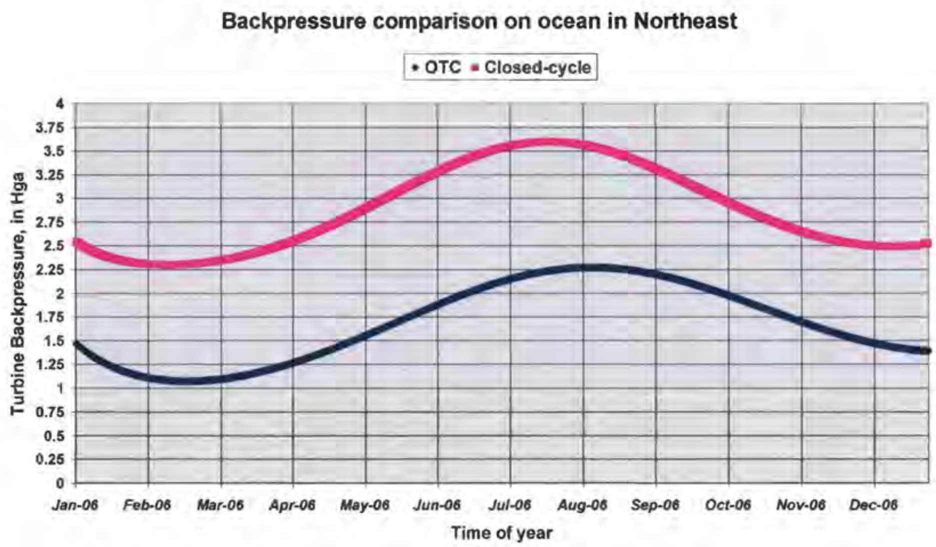


Figure 7-15: Backpressure comparison with ocean cooling in Northeast

The examples in Figures 12 through 14 show the effect on turbine exhaust pressure. The resultant effect on plant efficiency and output as a result of increases in backpressure depends strongly on the characteristics of the steam turbine as discussed earlier. The slope of the heat rate vs. backpressure curve varies with the age of the turbine and the backpressure for which it was originally optimized. A typical range from a number of sources is from 1 to 2% reduction in output at full load steam flow for each 1 inch Hga increase in backpressure. The curve is non-linear and the slope increases with increasing backpressure. Therefore, a difference of 1 inch Hga in backpressure results in a larger reduction at higher backpressures. This exacerbates the situation on hot days when the backpressure is at its highest on either cooling system.

Costs of downtime

Certain elements of a cooling system retrofit can be performed while the plant continues to operate on the existing once-through cooling system. These would normally include site preparation, basin construction, and the erection of a new cooling tower and the installation of required electrical gear, motor control centers, and other auxiliary equipment needs. Large portions of the installation of new circulating water piping and pumps and the new make-up and blowdown lines and pumps can also be accomplished while the plant operates. However, those parts of the retrofit which involve tying into, re-routing, strengthening or otherwise modifying portions of the existing circulating water piping, the existing condenser and the existing intake/discharge structures will require that the plant be shut down and the existing cooling system be shut down and drained. This time, during which the plant is unavailable for the generation of power can represent a retrofit cost which, while not a capital cost but rather the loss of potential revenue, can be substantial. However, little information is available to this study from which to estimate, in any general way, a "typical" duration of plant downtime and an associated cost.

Two actual units retrofitted at a mid-sized coal fired plant in the Southeast experienced downtime of approximately two months per unit related to the tie-in of the new circulating water lines to and from the cooling tower to the existing condenser loop. In this situation, the access to the tie-in points, while confined and restricted, did not appear to be exceptionally so. To the extent that this represented an "Easy" tie-in situation, this might constitute a lower bound on the time required for the final connection.

On the other hand, engineering estimates (not actual retrofit experiences) were made for the two large nuclear plants on the California coast and reported in the public literature (7-3). The downtime for San Onofre Nuclear Generating Station was "conservatively estimated" at six months per unit with a lost of generation of over 6 million MWh and lost revenue of nearly $600 million. The corresponding estimate for Diablo Canyon was 8 months per unit (with the observation that the integrated nature of the plant would require both units to off-line at the same time) and a loss of over 10 million MWH at a cost of approximately $725 million. (A current study, as yet unavailable, is reported to arrive at a much longer estimate of required downtime.)

The relationship between actual downtime and lost revenue can vary from one situation to another. For base-loaded plants essentially all the downtime represents a loss of needed generation and revenue. However plants with low capacity factors and peaking plants may have extended periods during the year when they do not operate. In principle, some retrofit activities could be scheduled for periods when the plant would not be expected to run. A plant-by-plant analysis of this situation and any estimate of the total or average national costs are beyond the scope of this study.

Re-optimization

The usual approach to a cooling system retrofit, as previously noted, is to install a cooling tower into an existing circulating water loop with no change to the circulating water flow rate or to the existing condenser. However, this approach may not be preferred in all circumstances. An important consideration in cooling system retrofits is whether the entire cooling system should be re-optimized to account for design selection differences between once-through and closed-cycle cooling. First, once-through systems are designed with higher cooling water flows and, hence, lower cooling water temperature rise than are closed-cycle systems. This is a result of the lower pump head requirements for once-through as opposed to the need to pump water to the top of a cooling tower in closed-cycle systems. Second, the condenser is often smaller with a higher terminal temperature difference (TTD) in once-through systems, particularly in situations where the reliable availability of cold water allows the maintenance of low condensing temperatures even at the higher condenser hot water exit temperatures. Third, for a given heat load, a cooling tower designed to cool a lower water flow over a greater cooling range will be smaller and less expensive and will consume less operating power than tower designed to cool a greater flow over a smaller range.

If, therefore, the retrofit consists simply of putting a cooling tower into the existing circulating water loop and retaining the existing condenser and cooling water flow rate, the system is far from optimum. The result is a low initial retrofit cost, but significantly higher penalty costs for the life of the plant. The usual result of a re-optimization is a reduction in the circulating water flow rate, often by as much as a factor of x2. This effectively halves the additional pumping power required and, by allowing the use of a smaller, more effective cooling tower, similarly reduces the number of fans and the associated fan power. These savings can represent over 0.5% of plant output over the remaining life of the plant.

However, the reduction in flow rate normally requires that the condenser be rebuilt, usually by changing it from a single-pass to a two-pass configuration in order to maintain the water velocity in the tubes at a high enough level to provide good heat transfer rates. For plants with low capacity factors and short remaining life, the simplest, least costly retrofit is likely to be the appropriate choice. For newer, baseload plants (including most nuclear facilities), which have an expected remaining life of twenty or more years, a full re-optimization may be the preferred approach.

However, as has been noted, the information upon which the retrofit cost estimates used in this study are based is, with but one exception, made up of cases where the usual approach was taken. Therefore, essentially no information is available upon which to base the range of costs which would be incurred for cases in which the system was re-optimized. While a study of the economic tradeoffs between the two approaches is beyond the scope of this study, it can be estimated that a full re-optimization would:

1. Put any retrofit project at a cost commensurate with the "Difficult" level. Condenser modifications can be expected to be particularly costly at most plants due to the crowded conditions surrounding the condenser and structural interferences from the turbine building walls. In addition, the change from a one-pass to a two-pass condenser would require waterbox modifications, relocation of the inlet or outlet piping to the opposite side of the turbine pedestal and possibly extensive changes to the structural foundations supporting the turbine.
2. Extend the downtime required for the retrofit significantly. While insufficient information is in-hand to estimate the downtime duration in either case, in broad terms it is likely to be increased from "several weeks" to "several months".

Natural draft cooling towers

The choice of natural-draft towers, instead of mechanical draft towers, is rarely made in retrofit applications although a natural draft tower was recently chosen for a cooling system retrofit currently under construction at a plant in the Northeast. Natural draft towers were frequently the cooling system selected for new plant construction of larger nuclear and coal-fired plants in the U.S. in the 1970's and 1980's. There are over 100 natural draft towers currently in operation in the U.S. although no new ones have been built for over 20 years ntil this current retrofit project in the Northeast. They normally are somewhat higher in capital cost but have significantly lower operating power requirements and reportedly lower maintenance costs. They also, because of limitations on air flow and fill height as a result of using buoyancy as the natural draft driving force, are designed for higher approach temperatures, typically 12 °F to 18 °F or higher compared to perhaps 6 °F to 12 °F for mechanical draft towers. For a given ambient condition this results in a higher turbine exhaust pressure as was discussed earlier in this section on energy penalty analysis. The combination of higher capital cost with lower operating cost can be the preferred solution for new plants with long expected life and high capacity factor. This was the case in the recent choice of natural draft towers for a new nuclear unit being planned in the Southeast. For the retrofit of existing units, if natural draft towers are chosen, it is normally for other reasons such as concern over ground level fogging as was the case for an existing retrofit project in the Northeast.

A single, well documented example for a large, base-loaded nuclear plant in the mid-Atlantic region reported a 5% higher capital costs with a 24% reduction in O&M costs and a reduction in energy/capacity penalty costs of about 30%. These costs, aggregated as a present value cost over a 13-year period from the start of retrofit construction, showed a 2.5% lower cost for the natural draft case. However, it should be noted that the long elapsed time since there has been any experience with the construction of natural draft towers in this country suggests a higher degree of uncertainty in cost estimates for natural draft tower installation. Also, the height and bulk of a large hyperbolic tower may create site-specific licensing problems in the form of aesthetic objections from neighboring populations.

Finally, the information from which the retrofit costs estimates in this study are derived comes entirely from studies and projects using mechanical draft towers. Therefore, no conclusions are drawn on the cost of using natural draft towers for closed-cycle wet cooling retrofits other than to note that it might be worthwhile to conduct an economic evaluation of natural draft towers as an alternative to mechanical draft in analyzing a cooling system retrofit at large, base-load plants with long remaining life.

Dry cooling

Some discussions of cooling system retrofits address the use of dry cooling as an alternative to closed-cycle wet cooling as a possible retrofit option. Dry cooling systems are of two types. The more common is direct dry cooling in which turbine exhaust steam is condensed in an air-cooled condenser. The other is indirect dry cooling in which the steam is condensed in a water-cooled, shell-and-tube condenser, as in once-through and closed-cycle wet cooling systems, and the hot condenser exit water is cooled in an air-cooled heat exchanger and then recirculated to the steam condenser. Direct dry cooling has seen increased acceptance as the cooling system of choice on some new power plants in the U.S. in recent years. No indirect all-dry cooling systems exist on U.S. power plants at this time.

Dry cooling of either type was not considered in this study for several reasons. First, given that closed-cycle wet cooling typically reduces the water withdrawn for cooling by 90 to 98 % of that required for once-through cooling, the use of dry cooling would represent only a small incremental further reduction in water intake rates. However, dry systems, in essentially all situations, are far more costly, require significantly more operating power and impose significantly higher efficiency/capacity penalties on the plants than is the case for wet systems. An engineering study of a California coastal plant (7-4) showed a doubling of the capital cost and a tripling of the operating/energy penalty costs for dry cooling in comparison to wet cooling. In addition, the physical size of air-cooled equipment occupies four to six times the land area and is two to three times higher than a corresponding mechanical-draft, wet cooling tower exacerbating the siting problem at existing plant sites.

Finally, the output limitation on hot days, which are normally coincident with days of highest demand for power, would be unacceptable with turbines originally designed for use with once-through cooling with a typical backpressure limitation of 5 in Hga. The use of dry cooling for retrofit in many situations would require turbine replacement with turbines capable of operation at higher backpressure as are used on new plants designed for dry cooling. The additional cost and the duration of plant downtime for such an extensive re-optimization and retrofit are unknown but would clearly significantly exceed the costs and duration of the more usual retrofit. The disadvantages are particularly significant for nuclear plants which suffer higher penalties with increased turbine exhaust pressure and are typically base-loaded.

The conclusion to exclude dry cooling from further consideration and discussion for plant cooling system retrofit is consistent with those of other studies of the subject including the TetraTech study (7-3) for the California Ocean Protection Council and the work of EPA in the development of the original Phase II rule (7-5).

Environmental and permitting issues

The impetus for the interest in the conversion of once-through cooling to closed-cycle cooling derives from a desire to reduce perceived environmental harm (fish and shellfish impingement and entrainment) resulting from the withdrawal of large quantities of water from natural water bodies into a power plant. To achieve this, reductions in aquatic life mortality from entrainment and impingement of varying percentages are likely to be proposed. While these might be achieved in a variety of ways, it is generally conceded that, if the intake flow is reduced to a level consistent with closed-cycle cooling, the requirements would be considered to be met.

As noted in Section 1, the regulations for new plants were promulgated in December, 2001 (with minor amendments in July, 2003) and nearly all new plants now use closed-cycle wet or dry cooling systems. The rule for existing plants was issued in July, 2004 and did not specifically require closed-cycle cooling but noted that conversion to closed-cycle cooling, if chosen, would satisfy all requirements. Since the remand of the rule by the 2nd Circuit Court in 2007 (Ref. 1-4) and the subsequent ruling by the Supreme Court in 2009 (Refs. 1-5, 1-6), as described in Section 1, the EPA has been working on revisions to the rule. The interim guidance from EPA to their Regional Offices is to exercise their "Best Professional Judgment" in determining NPDES permit requirements.

The emphasis in the bulk of this study has been on describing a methodology for making reasonable estimates of the capital, operating and maintenance costs involved in closed-cycle cooling retrofits with particular attention to those site-specific issues which might cause such retrofits at individual sites to be particularly costly. However, in addition to quantifiable financial costs, there are other considerations which affect the desirability and the feasibility of closed-cycle cooling system retrofits. These may be thought of in two categories. The first is other regulatory requirements which may apply to closed-cycle systems but were not pertinent to once-through cooling. The second recognizes that closed-cycle cooling systems are not without environmental and social impacts of their own, some of which were not present with once-through cooling (see companion EPRI 2010 report)

Other regulatory requirements

It is not the intent herein to provide an in-depth analysis of all possibly relevant regulatory or policy documents which might affect the process of permitting a cooling system retrofit project. This and related matters are not primary subjects addressed by this study, but are examined in detail in a companion study on "Quantification of the adverse environmental and social impacts associated with closed-cycle cooling" identified in Chapter 1 (7-6). For convenience of refernce, a brief listing is provided of those items. Specific regulatory requirements which must obviously be complied with are contained in the Clean Water Act and any pertinent State regulations.

The Clean Water Act regulates cooling tower blowdown under NPDES rules and establishes water quality-based effluent limits. If any of the sites are near wetlands, other provisions might apply.

The Clean Air Act contains a number of possibly pertinent programs including New Source Review, New Source Performance Standards, and National Ambient Air Quality Standards. The most important issues to consider are likely to be whether or not a cooling system retrofit would trigger any of the new source conditions. This may depend on whether the retrofit is then followed by an increase in the operating hours of a plant. The most important consideration will be PM10 emissions from a cooling tower. Whether or not this would be regulated appears to depend on the location of the facility since cooling towers are not treated uniformly in all jurisdictions. In some cases, offsets may be required. In any case, these proceedings can add appreciably to the complexity and cost of the project. However, these costs are not captured in this analysis.

Environmental effects

All cooling systems have some effect on the environment. As noted above, the potential regulatory driver for this study is the possible required reduction of any effects on aquatic life from intake losses. The degree of the environmental harm resulting from the intake of cooling water from natural waterways has been the subject of a vast number of general analyses and site-specific studies over decades. However, while it is unquestioned that the use of recirculated cooling at a power generation plant will substantially reduce the amount of cooling water drawn into the plant, there are accompanying effects of a cooling system retrofit that merit consideration. These include:

- Increased air emissions
- Drift and visible plumes
- Water and waste discharge and disposal
- Noise
- Aesthetics
- Water consumption
- Construction related effects
- Intake losses

Each of these is briefly reviewed in subsequent sections.

Increased air emissions

The primary air emissions from fossil plants are from the combustion of the fuel. As has been noted, the choice of cooling system can reduce the overall plant efficiency and capacity. Therefore, to meet a given total system load, more fuel must be burned with a corresponding increase in emissions of NO_x, particulate matter, SO_2 and CO_2 in amounts and proportions which depend on where and in what equipment the additional fuel is used.

The methodology for determining the additional power that must be generated and the additional fuel that must be burned was discussed earlier in this chapter. Two factors must be considered. First, closed-cycle cooling systems consume more operating power for increased circulating water loop pumping power and for the additional requirement for cooling tower fan power. Additional operating power requires that the gross generation be increased in order to hold the net output constant. Second, the increased turbine backpressure increases the plant heat rate and requires more fuel to be burned even to maintain the same gross generation. However, once this additional fuel consumption is estimated from a performance comparison between the two cooling systems, the effect on air emissions depends on a several factors.

Many of the Phase II plants have low annual capacity factors. In addition, even when operating, they are frequently at less than full load. In these cases, the reduction in net generation would be made up simply by increasing the firing rate. The increased emissions would then be of the same type and at the same location and would increase in direct proportion to the firing rate.

There are, however, many circumstances in which the desired net output could not be maintained from the same unit, either because the unit is already being dispatched at full load (likely to be the case for most facilities during periods of peak energy demand) or operating concerns will not allow the turbine to run at the elevated backpressure. In such cases, the deficit in net output at the one unit must be made up elsewhere. A number of options exist. The load may be replaced with another, perhaps identical, unit at the same plant. The increased air emissions are again simply proportional to the combined firing rate and would be of the same composition and subject to the same local regulations. Alternatively, the replacement power may come from a similar steam unit at another plant. In this case, the increase in emissions may be similar to the previous case and the emissions will be similar or identical in composition, but differences in the local situations may present more or less severe constraints.

A third possibility is that the power will be replaced from units of different types. If these are fossil units, such as simple-cycle gas turbines or gas-fired combined-cycle units, the increase in emissions may be less than if the replacement came from other older steam plants because of lower heat rates and perhaps more modern and efficient environmental controls. If the replacement power were to be obtained from non-fossil units such as nuclear, solar or wind, this would certainly be the case.

Finally, if the power were to be replaced with power generated at distant plants, the emissions may be greater in magnitude and different in character. While local emissions would not be increased, the national loading would be. In some circumstances, the emissions may be transferred to locations where they are of less concern. However, if the emissions of greenhouse gases are of concern, their global effect is independent of location.

In sum, the effect of increased air emissions, with the possible exception of PM_{10} and $PM_{2.5}$ which will be discussed in a later section, from cooling system retrofits would appear to be modest even if much higher increases in typical heat rate could be demonstrated. However, the effect of a decision to retrofit an individual plant, like the financial cost itself, must be evaluated on an individual, site- and situation-specific basis.

Drift and visible plumes:

Drift

Drift rates from modern, well designed cooling towers can be held to quite low levels. New installations have been quoted at less than 0.0005% of the circulating water flow rate. However, even that low rate will result in a total drift of nearly 2000 gallons per day from a 500 MW steam plant circulating 250,000 gpm. The environmental issues normally raised in connection with cooling tower drift are PM10 emissions, bacterial or pathogenic emissions and damage to local crops.

A very thorough discussion of the technical and regulatory aspects of all emissions from cooling towers including PM10 and PM2.5 are given by Micheletti (7-7) and EPRI (7-?).

- PM10: The source of concern over PM10 is that, as the drift droplets evaporate, the dissolved and suspended solids in the circulating water are released as air-borne particles. PM10 emissions are usually estimated (conservatively) as 100% of the TSS and TDS in the estimated drift. As the discussion by Micheletti, along with recent study by Reisman and Frisbie (7-8) demonstrates, the use of the EPA recommended emission factor combined with the assumption that all particles from evaporated drift are classifiable as PM10, likely leads to a vast over-estimate (by a factor of 10 or more) of PM10 emissions for a modern, well-design and constructed cooling tower. This over-estimate, coupled with the use of seawater for make-up and the resulting very high TDS levels in the circulating water, can lead to predictions of very high PM10 emission rates. The rules for cooling towers vary, but, if PM10 offsets should be required, the costs could be substantial even if the offsets were available. However, this may still be a consideration in some areas.

- Infectious species: The most frequently cited public health issue in the context of cooling towers is the possibility of Legionnaire's Disease, so-called because of an outbreak at an American Legion convention in Philadelphia in 1976 attributed to pathogens (*legionella pneumophilia*) in the cooling tower for the HVAC system in the hotel. While the frequency of occurrence of Legionnaire's Disease is small (approximately 1400 cases reported to the Center for Disease Control annually) and the number of these attributable to cooling towers (at power plants or anywhere else) is even fewer, the question has been investigated extensively in the U.S. and abroad (7-??). Treatments of the issue are found in the CTI and ASHRAE literature and references therein.

  While the consequences of exposure can be very severe and even fatal particularly to at-risk (the elderly, smokers, individuals with chronic respiratory problems or with suppressed immune systems) populations, the evidence of harm is sparse and largely anecdotal. Cooling towers are a common element of our industrial, commercial and residential scenes in high-density population areas in all climates. No compelling epidemiology has established a significant threat.

  However, expressions of concern during permitting hearings are to be expected, particularly if the use of reclaimed municipal water is proposed even though tertiary treatment is required for any reclaimed municipal water to be used in cooling towers.

- Deleterious impacts of power plant cooling systems on surrounding agriculture have not been an issue except in a few special circumstances. One notable study was conducted in the mid-1970's at the Potomac Electric Power Company's Chalk Point Station in Maryland. In that case, the towers were run on brackish make-up water with a circulating water salinity comparable to sea water (35,000 ppm TDS); the towers were hyperbolic natural draft towers with a plume exit plane elevation of about 400 feet; and the plant was located in a tobacco-growing region with a specialty crop of leaves intended for use as the outer wrappers of cigars. High salinity droplet deposition on the leaves could create small, discolored spots making the leaf unusable without in any way affecting the health of the plant or the quality of the soil. Even under these conditions, the risk was eventually determined to be negligibly small, and the plant and towers continued to operate with no special controls and no adverse impact on the region's agricultural activity.

  A more extensive discussion of this subject is available in a recent report on salt water towers (7-9).

Visible plumes

On cold days, wet towers can produce a large visible plume as the warm saturated air leaving the tower mixes with the cold ambient air and water vapor condenses. In some locations, these plumes may obscure visibility, creating dangerous conditions on roadways or, along with drift, lead to local icing on neighboring roads or structures. In at least one instance, the Streeter plant in Cedar Falls, Iowa, a retrofit of a dry cooling tower was performed in order to eliminate plume effects on a nearby highway. Similar concerns led to the selection of a natural-draft wet tower for the retrofit at a Northeastern facility.

If a visible plume is deemed unacceptable, a cooling tower can be designed with plume abatement capability. This is accomplished by adding an air-cooled section to the tower and mixing the heated air off the dry section with the saturated air off the wet section to decrease the relative humidity of the mixed plume. Further mixing with the colder ambient air can then avoid the super-saturation zone where water vapor condensation and plume visibility would occur. A detailed discussion of the principles governing visible plume formation and the design options for plume abatement towers is given in Lindahl and Jameson (7-10).

Fixing the design point requires the determination of the combination of ambient wet and dry bulb temperatures at which a visible plume will form and the number of hours per year during which those conditions pertain. It also needs to be decided under what circumstances a visible plume may be acceptable. If the issue is aesthetics, for example, a plume during hours of coastal fog or at night may well be acceptable. If the issue is highway or airport safety, on the other hand, any occurrence of a plume may be unacceptable.

The costs of plume abatement towers, both capital and operating costs, increase as the number of allowable hours of plume formation decrease. Estimates by Mirsky (7-11) used by EPA in their 316 (b) Development Document (7-5) suggest that a 32 °F dry bulb limit on plume formation can increase the cost of the tower relative to a normal wet cooling tower by factors of x 2.5 to x 3.0 for the capital cost and x 1.25 to 1.5 for the operating cost.

Wastewater and solid waste

Potential issues regarding the return of cooling tower blowdown to local receiving waters will require careful, site-specific attention. Cooling towers using seawater for make-up would presumably blowdown back to the ocean, bay or estuary. The California Ocean Plan has no salinity limits, but local Total Maximum Daily Load (TMDL) requirements may limit discharges, particularly into bays or estuaries. Regulatory constraints such as pertain in California where the State Implementation Policy for implementing the receiving water standards in USEPA's California Toxics Rule allow a discharger who takes water from an impaired water body to discharge back to that water body only if the concentration of the pollutants has not been increased. This offers relief to once-through cooling, but at plants that use cooling towers, blowdown treatment would be required. This would require consideration of the disposal of solid waste, such as basin sludge or water treatment system sludge from evaporation ponds, brine concentrators, side-stream softeners or other blowdown reduction processes.

For plants considering the use of reclaimed municipal water for tower make-up, the normal procedure is to return the blowdown to the municipal treatment plant. In such cases, the increase salinity in the blowdown may present an operational problem to the wastewater treatment facility.

Noise

Cooling tower operation is noisier than once-through cooling operation. The primary noise from cooling towers is a combination of fan noise and "fill" noise caused by the flow of water down over the tower fill. Two limits must be considered. The first applies to worker safety and is set by OSHA. Cooling towers typically have no problem meeting these limits. The second is set by local or state ordinance either at the plant boundary or at some point in a neighboring area, such as the nearest receptor. This limit can vary from none to strict depending on the local situation. If strict limits apply, fan noise can be reduced through the choice of low noise fans, the water noise is less amenable to reduction and some sort of sound barrier may be required to comply with local ordinances. Here again, the issue may simply add to the difficulty of obtaining a permit, add to the cost and duration of the project and warrant consideration in the larger context of balancing the overall benefits to the environment and society of a given decision affecting the choice of cooling systems at power plants.

Aesthetics

In some cases, where plants may be sited in a scenic or urban area, cooling towers may be deemed as a significant impact on the aesthetics of the locality. In many of the sites of interest to this study, this can be a very important consideration. For example, the scenic beauty of coastal areas from the beaches or from scenic drives on highways paralleling the shore is a treasured resource. The preservation of this resource is specifically protected in many venues and the issue is frequently addressed in siting hearings.

The uncertainty lies in the adage that "beauty is in the eye of the beholder", and it is difficult to know how to establish the importance of this factor. It would be expected to be very site specific. However, there is little doubt that it could result in a contentious permitting issue, leading to delays or even denial of permits and consequently increased costs or premature facility retirement if there is no regulatory relief to comply with a retrofit requirement..

Water consumption

While once-through systems, as noted above, withdraw large quantities of water, they return all of the withdrawn water back to the source (or at least to nearby natural waterbodies). A recirculated cooling system, while withdrawing far less water, is designed to cool by evaporating a portion of the circulating water flow in order to cool the remainder. A typical evaporation rate for mechanical draft cooling towers is 10 gpm/MW representing 50 to 80% of the intake flow, again depending on the cycles of concentration. This loss of water to the source waterbody will exceed losses associated with increased evaporation rate from the receiving waters of a once-through cooling system. In some situations on some fresh waterbodies such as small rivers or lakes, this can be an important consideration.

Construction related effects

The site preparation and digging required for the installation of a cooling tower basin and new circulating water lines will involve the disturbing and disposal of potentially large amount of soil. In some situations, the soil on the plant site may be contaminated with oil or other organic substances from prior use. While this presents no problem if left undisturbed, it could present a significant permitting and financial burden for retrofit operations. The associated cost is impossible to generalize and would need to be developed on a site-specific basis.

Fish and shellfish losses

As shown in Figure 3-2, the cooling water flows for the once-through systems range from 400 to 800 gpm per MW and occasionally higher. Cooling water intake for recirculated cooling systems using mechanical draft cooling towers with a typical evaporation rate of 10 gpm/MW ranges from 11 to 13 gpm/MW for fresh water make-up but as high as 20 to 30 gpm/MW for salt water make-up depending on the cycles of concentration at which the tower is operated. While this represents a ten- to seventy-fold reduction in the water taken into the system, it may not represent a similar reduction in the degree to which "fish, shellfish and other aquatic life are killed or injured". The survival rate of organisms entrained or impinged in once-through systems has been studied and debated extensively. A review of entrainment survival studies indicates impingement and entrainment survival can be significant (7-12). It is, however, extremely unlikely that entrained organisms will survive passage through a recirculated cooling system with a cooling tower.

It should be noted, however, that even for as little as a ten-fold reduction in withdrawal rate, the survival rate for entrained organisms into once-through cooling systems would have to be 90% or greater in order for the entrainment losses in a closed-cycle system to equal or exceed those in a once-through system. For a twenty-fold reduction, the once-through survival rate would need to exceed 95%.

References-- Chapter 7

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8

NATIONAL COSTS

The national cost of retrofitting all the Phase II facilities listed in Appendix A is estimated by an extrapolation of the costs for plants for which information was available using the average cost factors for each "difficulty" category developed in Chapter 3 and the analyses of 125 specific plants as described in Chapters 4 and 5. The extrapolation is based on the total of the circulating water flow rates for the individual plants as tabulated in Appendix A.

Circulating water flows

Of the 444 Phase II facilities, 404 are fossil plants, 40 are nuclear plants. Plant capacities and circulating water flow rates are included on the list in Appendix A. All of the flow rate data were obtained from independent sources. In a few instances, when plant capacity data were not found, the capacities were estimated at 1 MW per million gallons per day of cooling water flow, corresponding very closely to the average of all the plants for which independent data were available. The data are summarized in Table 8.1 for both fossil and nuclear facilities.

Table 8-1: Capacity and water flows at Phase II Facilities

Plant Type	No. of plants	Total capacity	Total circulating water flow
		MW	gpm
Fossil	404	265,592	144,323,644
Nuclear	40	61,444	41,683,466
Total	444	327,036	186,007,110

Capital cost extrapolations

The widest range of costs for the complete family of Phase II facilities was estimated by determining the costs that would result if <u>all</u> the fossil plants were in the easy, average, difficult or more difficult categories and <u>all</u> the nuclear plants were either less difficult or more difficult. The range of results for these alternate assumptions is shown in Table 8.2.

Table 8-2: Possible range of national costs for all Phase II facilities.

Plant Type	National Cost Ranges for Varying Degrees of Difficulty, $ millions					
	Easy	Average	Difficult	More Difficult	Less Difficult	More Difficult
Fossil	$26,120	$39,690	$58,450	$82,260		
Nuclear					$11,420	$26,840
All	Minimum	Average	Maximum			
	$37,540	$58,820	$109,110			

The normalized cooling water flow in gpm/MW was calculated for each of the 444 facilities. The results for a few of the facilities appeared to be either unrealistically low (<200 gpm/MW) or unrealistically high (>1,200 gpm/MW). In attempt to understand the possible effect of these plants on the overall results, the range of costs displayed above was first calculated using only those facilities for which the normalized cooling water flow lay between 200 and 1,200 gpm/MW. Those plants represented over 96% of the MW and cooling water flow, so the costs were scaled up by 4% and compared to the values obtained from the entire set of plants. The agreement was within 1%. Therefore, for purposes of extrapolation to national totals the data were used as listed.

As indicated in Table 8.1, for the 404 fossil plants, the range of capital costs based on the cost correlations for the total flow ranges from $26.1 billion, if all were ranked "easy" to $40 billion if all were ranked "average", to $58 billion, if all were ranked "difficult" and as high as $82 billion if all were tanked "more difficult". Corresponding numbers for the 40 nuclear plants range from $11 billion (all ranked "less difficult") to $27 billion (all ranked "more difficult"). The estimated capital cost for all 444 plants ranges from a minimum of $38 billion to a maximum of $109 billion with a mid-range estimate of $59 billion.

The range can be narrowed by considering the distribution of the plants subjected to site-specific analysis and assuming that they constitute a representative distribution of the complete family of Phase II plants. Plants representing approximately 17.5% of the fossil capacity were judged to be "Easy", 45% to be "Average", 30.5% to be "Difficult" and 7% to be "More difficult".. For the nuclear plants, approximately 25% of the capacity was "Less Difficult" and 25% "More Difficult" with the remaining 50% judged to be intermediate. This was for a very small sample, but the range of independent cost estimates as displayed in Figure 3-15 supports such an allocation. Applying this distribution to the complete set of Phase II facilities results in the costs displayed in Table 8.3.

Table 8.3: National retrofit costs with estimated degree of difficulty allocation

Plant Type	Degree of Difficulty	Allocation	Flow	Cost
		%	gpm	$ millions
Fossil	Easy	17.5%	25,257,000	$4,570
	Average	45.0%	64,946,000	$17,860
	Difficult	30.5%	44,019,000	$17,830
	More Difficult	7.0%	10,103,000	$5,760
Total fossil		100.0%	144,325,000	$46,020
Nuclear	Less Difficult	25.0%	10,420,867	$2,860
	More Difficult	25.0%	10,420,867	$6,710
	Intermediate	50.0%	20,841,733	$9,570
Total nuclear		100.0%	41,683,466	$19,140
Total Phase II			186,008,466	$65,160

This results in a cost of $46 billion for the fossil plants, $19 billion for the nuclear plants and a total for the family of Phase II facilities of approximately $65 billion or approximately 10% above the mid-range estimate in Table 8.2.

While a number of other extrapolation procedures might be considered such as applying the same allocation of degree of difficulty to the Phase II family as was found for the plants analyzed by region, or water type or type of surroundings, the variation around this more simple allocation is within +/-10% in all cases. Given that the level of accuracy of the estimating methodology for individual plants is no better that +/-20%, any attempt to select a preferred national total from among the various approaches to extrapolation would have a very limited confidence level. Therefore, a range of capital costs of +/-10% around the total given in Table 8.3 or from $60 billion to $72 billion is the best estimate that can be provided at this time.

However, given that there has been some speculation that the requirements may vary according to source water type, a division of the total costs among the source water types of rivers, lakes and reservoirs, Great Lakes and "oceans, estuaries and tidal rivers" may be useful. Each of these categories contains a large enough sample of plants that the allocation of degrees of difficulty developed for the total Phase II family of plants will be applied unchanged to each of the source water type categories. The results are listed in Table 8-4.

Table 8-4: National costs for each water source type

Source Type	GPM			Capital Costs, $ millions		
	Nuclear	Fossil	All	Nuclear	Fossil	Total
GL	3,811,713	15,546,886	19,358,600	$1,750	$4,957	$6,707
Lakes and reservoirs	13,956,938	35,856,765	49,813,703	$6,406	$11,433	$17,839
O/E/TR	16,403,018	40,328,525	56,731,543	$7,529	$12,859	$20,388
Rivers	7,511,798	52,591,467	60,103,264	$3,448	$16,769	$20,217
Total	41,683,466	144,323,644	186,007,110	$19,133	$46,018	$65,150

Other costs

It should be recognized that the costs tabulated above in Table 8-4 include the capital costs of retrofit only. However, there are other costs which would result from retrofitting all the Phase II facilities with closed-cycle cooling, and they are significant. These include:

- cost of energy replacement incurred during plant outages during the retrofit activity
- cost of increased operating power requirements from closed-cycle operation
- cost of increased maintenance of closed-cycle cooling systems
- cost of energy replacement or increased fuel use resulting from reductions in plant efficiency and capacity from closed-cycle cooling performance limitations and
- any related permitting costs.

Energy replacement during outage

As discussed in Section 7, the process of retrofitting an existing once-through cooled unit to closed-cycle cooling will require that the unit be off-line for an extended period. During this time, the energy which the unit would have generated must be replaced from other sources. Information that would be required for a detailed estimate of the required downtime, the associated replacement energy and its cost is unavailable to this study. The following paragraphs outline an approach to developing a generalized estimate of this cost element on a national basis.

Outage duration

In many cases, the cooling tower itself and much of the circulating water piping, pumps, sumps, valves and provisions for system make-up and blowdown can be constructed and installed while the plant continues to operate on the existing once-through cooling system. However, the plant must be off-line during periods when the cooling water flow to the steam condenser is interrupted or, when critical elements of the plant infrastructure must be disabled or relocated to make room for the tower or other elements.

Some plant outage will always be required for the tying-in of the new circulating water system to the existing condenser's intake/discharge piping. More extended downtime is required if structural reinforcement of the condenser or existing water tunnels is needed to withstand increased circulating water pressure. If significant condenser modifications such as are required for system re-optimization as was discussed in Section 7, the outage can be quite long. It was noted that re-optimization is most likely required for baseload plants with long remaining life. With this in mind, expected downtimes were assigned to different groupings of the family of Phase II facilities as follows:

1. Nuclear plants---It is assumed that <u>all</u> nuclear plants are base-loaded and that all have a sufficiently long remaining life (say, 5 to 10 years) to justify re-optimization. Recent studies (8-1, 8-2, 8-3, 8-4) of cooling system retrofits at nuclear plants all estimate outage times of 8 to 18 months. Therefore, an intermediate duration of 12 months will be used for all nuclear plants.
2. Fossil plants--- Of the 404 fossil facilities, 307 provided unit specific capacity utilization data for a 5 year period. A review of the unit specific capacity data determined that 27.1% of the generation for all 307 facilities was base-loaded with capacity factors of 75% or more. Assuming the 27.7% base-loaded capacity utilization data is representative of all 404 fossil facilities (265,592 MW) there is a total of 71.975 MW of base-loaded fossil generation.
    a. Assume that one-half of the base-loaded facilities (35,988 MW) have a long enough remaining life to justify re-optimization requiring a one-year downtime.
    b. For the other half of the base-loaded facilities, it will be assumed that those rated as "Easy" or "Average" retrofits will be able to complete the retrofits during scheduled outage periods with no downtime penalty. The "Difficult" sites will be assumed to require 4 months downtime; the "More Difficult" case, 8 months;

Valuation of costs

The cost of the downtime is estimated in two steps:

1. Replacement energy required is estimated by multiplying the plant capcity (MW) by the assumed outage duration (hours) reduced by the average capacity factors. The capacity factor estimates are based on data from the U. S. Energy Information Administration (8-5). The results for the full U. S. fleet on nuclear and fossil plants are shown in Table 8-5. Although the average age of the Phase II plants is likely somewhat older that the U. S. average, no information is available to make that adjustment, and the national capacity factors are applied to the Phase II plants for purposes of this estimate.

2. The cost per MWh of replacement energy can be valued as "lost revenue" to the particular plant or at the differential generation cost between the particular plant and other plants on the system which presumably have higher generation costs. Either of these costs can vary significantly throughout the year and from site to site and from system to system. A detailed analysis of these costs is beyond the scope of this study. A single value for the cost of replacement energy has, therefore, been set at $35/MWh for this estimate. The amount of replacement energy required and the cost to provide it for the nuclear plants and for the three groupings of fossil plants is shown in Table 8-6.

Table 8-5: Estimate of national capacity factors.

Plant Type	National Capacity	Annual Generation	Average Capacity Factor
	MW	MWh	%
Coal	315,500	2.02E+09	73.0%
Oil	61,500	6.57E+07	12.2%
Gas	427,700	8.97E+08	23.9%
Total Fossil	804,700	2.98E+09	42.3%
Nuclear	102,500	8.06E+08	89.8%

Table 8-6: Estimate of energy replacement costs.

Plant Type	Capacity of Phase II Units	Average Capacity Factor	Outage Duration	Annual Generation	Downtime Cost (@ $35/MWh)
	MW	%	Months	GWh	MM$
Nuclear	61,444	90%	12	484,424	16,955
Fossil					
Baseload/Long life	35,988	90%	12	283,727	9,930
Remaining-Easy_Average	143,503	42%	0	0	0
Remaining-Difficult	70,029	42%	4	85,884	3,006
Remaining-More difficult	16,072	42%	8	39,422	1,380
Total Fossil	265,592			409,033	14,316
Total Phase II	327,036			893,458	31,271

Operating power costs

An estimate of O&M costs for a given plant was discussed in Section 7. A gross estimate of the annual cost of increased O&M can be approximated as follows. The sum of the additional required operating power for the additional pumping head and the cooling tower fans was estimated to range from 0.9 to 1.3% of plant output. The maximum total additional power can be calculated by applying a factor of 13 kW/MW to the total capacity of the nuclear and fossil Phase II plants. For plants which re-optimize, the circulating water flow and the tower size will be essentially halved. Therefore, for all nuclear plants and for the fossil plants characterized as "Baseload/Long life", the additional power is estimated as 0.65 % of plant output.

Two additional questions must be considered. First, the additional power is consumed only when the plant is operating so an average capacity factor must be determined. The values tabulated in Table 8.5 are used.

The second question, as was the case for the downtime costs, is how to value the additional power required. For plants operating at full load, the added operating power subtracts from the energy available to send out and should be evaluated as lost revenue or the differential generation cost. For plants operating at part load, the firing rate can be increased to achieve the same net output and the cost is that for the additional fuel burned. On the basis of lost revenue, a penalty of $40/MWh might be a reasonable average. At an average heat rate of 10,000 Btu/kWh or 10,000,000Btu/MWh and $3/million Btu, the penalty, evaluated at the increased fuel cost, is $30/MWh. For purposes of this estimate, an intermediate value of $35/MWh will be used. The results are displayed in Table 8-7.

Table 8-7: Estimate of annual cost of additional power requirements

Plant Type	Capacity	Add'l Power	Average Capacity Factor	Annual Energy Consumed	Annual Cost (@ $35/MWh)
	MW	MW	%	MWh	$
Fossil, re-optimized	35,988	234	90.0%	1,844,000	$64,548,000
Fossil, standard	229,604	2,985	42.0%	10,982,000	$384,365,000
Total Fossil	265,592	3,219		12,826,000	$448,914,000
Nuclear	61,444	799	90.0%	6,297,000	$220,412,000
Total Phase II	327,036	4,018		19,124,000	$669,326,000

Energy penalty costs

A similar calculation can be made of the cost of the annual energy penalty resulting from the increased turbine backpressure and reduced turbine efficiency. Tables 7-3 and 7-4 list the differences in turbine backpressure at "hot day" (Table 7-3) and "annual average" (Table 7-4) conditions for example sites in seven geographical regions with differing climates and source waters. They show a wide range varying from -0.9 to 1.15 in Hga on hot days with an average of about 0.6 in Hga and from 0.55 to 1.41 in Hga with an average of about 0.9 in Hga at annual average conditions. As discussed in the section accompanying these tables, the differences stem from differences in the source water temperature for once-through cooling and the wet bulb temperature plus the tower approach for closed-cycle cooling.

It may seem counter-intuitive, given the attention normally given to "hot day" limitations, that the backpressure differences are higher at annual average conditions than at hot day conditions. However, two points must be considered. First, the turbine performance curves are non-linear and a given increase in backpressure results in a higher output reduction at the higher backpressure levels encountered on hot days than at the lower levels encountered at annual average conditions. Second, hot day conditions are typically days of high system loads when individual plants are operating at full load and being asked to maximize output. This likely means that they are already operating at high backpressure, possible approaching the "alarm" or "trip" point. Therefore, any additional reductions in output due to cooling system limitations are particularly noteworthy. Additionally, the price per MWh on hot days for some plants can be significantly above the annual average price so any output penalty is particularly costly.

An estimate of the aggregated national cost of the energy/capacity penalties associated with cooling system retrofits can be developed in a manner similar to that used for the cost of the increased operating power requirements.

The average backpressure increase across the seven regions will be used for the hot day and annual average conditions. The output reduction per unit increase in turbine exhaust pressure, expressed as "% reduction per in Hga" is assumed to be 1%/in Hga at annual average conditions and 2%/in Hga at hot day conditions. "Hot day" conditions will be assumed to pertain for 10% of the year (876 hours) and annual average conditions for the remainder of the year (7,884 hours).

Finally, the values of the lost output could be evaluated as lost revenue at the appropriate price per MWh, as increased fuel cost if the reduction can be made up by increased firing, or at the differential production cost if the load is replaced by another plant presumably with somewhat higher production costs. A detailed analysis of this issue is beyond the scope of this effort, and, as above, the reduced output will be valued at $35/MWh. It is recognized that, in some situations, the value of hot day output may be significantly greater than this, but the information is not available to apply such considerations to the national cost estimates. Table 8-8 tabulates the results of the estimating procedure.

Table 8-8: Estimate of annual cost of heat rate energy penalty

Plant Type	Capacity	Increased backpressure	Percent output reduction	Hours per year	Capacity factor	Cost (@ $35/MWh)
	MW	in Hga	%	Hr	$	$
Fossil						
Hot day	265,592	0.6	1.2%	876	84.0%	$82,081,951
Annual average	265,592	0.9	0.9%	7,884	42.0%	$277,026,585
Total Fossil						$359,108,537
Nuclear						
Hot day	61,444	0.6	1.2%	876	90.0%	$20,345,829
Annual average	61,444	0.9	0.9%	7,884	90.0%	$137,334,345
Total Nuclear						$157,680,173
Total	327,036					$516,788,710

Two cost elements of additional maintenance costs and permitting costs were identified earlier. Additional maintenance costs are highly dependent on site source water quality and operating procedures at any individual plant. They are sometimes factored as 2 to 3% of <u>equipment</u> cost which in turn is 15 to 30% of the retrofit capital cost resulting in minimum additional cost. Permitting costs, while potentially significant, are highly site-specific, and there is no obvious method for generalizing them. Therefore, both of these costs are omitted from the analysis.

Summary of costs

The four major cost elements are summarized in Table 8-9.

Table 8-9: Summary of cost elements

Plant Type	Capacity	Cost (MM$)			
	MW	Capital	Downtime	Annual operating power	Annual heat rate penalty
Nuclear	61,444	19,140	16,955	220	359
Fossil	265,592	46,020	14,316	449	158
Total	327,036	65,160	31,271	669	517

The "Capital" and "Downtime" costs are assumed to be incurred in the first year. The "Operating power" costs and the "Heat rate penalty" costs are incurred annually for the life of the facility. These costs are put on a common basis in two ways. The first is an annualized cost which amortizes the first year costs using an amortization factor of 7% and adds the result to the sum of the annual costs. The second is a net present value which discounts the present value of the annual costs which are incurred at dates in the future, using a discount factor of 7%, and adds the sum to the first year costs. These costs are tabulated in Table 8-10.

Table 8-10: Annualized costs and net present value

Cost	Nuclear	Fossil	Total
Annualized cost, MM$/yr	$3,106	$4,831	$7,936
Net present value*, MM$	$40,162	$64,600	$104,761

* Assumed 10 year life

References

1. Enercon Service, Inc., "Diablo Canyon Power Plant; Cooling Tower Feasibility Study, March, 2009.

2. Enercon Services, Inc., "Feasibility Study for Installation of Cooling Towers and the San Onofre Nuclear Generating Station", 2009.
3. Oyster Creek
4. Indian Point
5. U. S. Energy Information Administration Website; http://www.eia.doe.gov/fuelelectric.html

APPENDIX A

List of Phase II Facilities

Nuclear Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
N427	AR	1,102	765,000	L	Dardanelle Reservoir on Arkansas Riv	850
N203	AL	3,045	2,115,000	R (Large)	Tennessee River	3,660
N100	NC	1,921	1,333,734	O/E/TR (Small)	Cape Fear River	2,060
N475	MD	1,757	1,220,000	O/E/TR	Chesapeake Bay	1,735
N552	IL	889	617,500	L	LAKE CLINTON (dam on Salt Creek)	1,065
N340	TX	3,168	2,200,000	L	Squaw Creek Reservoir	2,300
N405	NE	983	682,807	R (Large)	Missouri River	802
N416	FL	979	680,000	O/E/TR	Gulf of Mexico	890
N321	CA	2,500	1,736,111	O/E/TR	Pacific Ocean	2,298
N285	MI	2,369	1,645,000	GL	Lake Michigan	2,161
N477	IL	1,898	1,017,000	R (Small)	Kankakee River	1,914
N260	NY	518	359,722	GL	Lake Ontario	852
N261	NE	518	359,722	R (Large)	Missouri River	478
N513	SC	740	514,100	L	Lake Robinson	700
N145	NY	2,420	1,680,484	O/E/TR (Large)	Hudson River	2,045
N486	WI	582	404,188	GL	Lake Michigan	595
N374	NC	2,928	2,033,064	L	Lake Norman	2,240
N150	CT	2,190	1,520,832	O/E/TR	Long Island Sound	2,205
N231	MN	444	308,000	R (Large)	Mississippi River	620
N253	NY	495	343,750	GL	Lake Ontario	1,778
N178	VA	2,707	1,880,000	L	Lake Anna	1,956
N188	SC	3,058	2,123,611	L	Lake Keowee	2,538
N506	NJ	1,394	968,333	O/E/TR	Barnegat Bay	630
N473	TX	1,681	1,167,450	O/E/TR	Galveston Bay	2,285
N201	PA	2,281	1,584,000	L	Reservoir within Susquehanna River	2,186
N234	MA	448	311,111	O/E/TR	Cape Cod Canal	685
N419	WI	1,008	700,000	GL	Lake Michigan	1,365
N413	MN	969	673,200	R (Large)	Mississippi River	1,150
N455I	IL	1,356	942,000	R (Large)	Mississippi River	1824
N269	NY	536	372,000	GL	Lake Ontario	581
N218	NJ	3,168	2,200,000	O/E/TR (Small)	Delaware River	2,540
N302	CA	2,335	1,621,528	O/E/TR	Pacific Ocean	2,150
N233	NH	447	310,416	O/E/TR	Atlantic Ocean	1,296
N471	TN	1,616	1,122,000	L	Chickamauga Reservoir	2,442
N459	FL	1,403	974,600	O/E/TR	Atlantic Ocean	1,700
N236	VA	2,534	1,760,000	O/E/TR (Small)	James River	1,802
N520	SC	720	500,000	L	Parr Reservoir	1,100
N262	VT	518	359,722	R(Large)	Connecticut River	650
N468	LA	1,555	1,079,861	R (Large)	Mississippi	1,165
N307	TN	194	135,000	L	Watts Bar Reservoir	1,270
N532	KS	763	530,069	L	Wolf Creek Lake	1,166

Fossil Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
492LA9J	LA	141	98,000	O/E/TR	Inner Harbor Nav Canal	148
503PA1K	PR	651	452,000	O/E/TR	Jobos Bay	900
439CA1S	CA	1,181	820,139	O/E/TR	Cerritos Channel	1,950
276TA88	TN	549	381,000	R (Large)	Mississippi River	864
243MA4L	MN	467	324,000	L	Lake St. Croix	605
548NA4M	NC	861	598,000	L	Lake Wylie	1,391
271WA8S	WI	540	375,000	R (Large)	Mississippi River	605
450FA29	FL	1,287	894,000	O/E/TR	Anclote River	1,030
199PA85	PA	179	124,306	R (Large)	Allegheny River	356
515NA2M	NY	713	495,139	O/E/TR	Lower New York Bay	875
338OA5C	OH	252	175,000	GL	Lake Erie	256
380NA4E	NC	316	219,600	L	Lake Julian (Powell Creek)	837
476NA35	NY	1,769	1,228,472	O/E/TR	East River	1,288
296OA52	OH	625	434,000	GL	Lake Erie	766
286MB5S	MI	583	405,000	GL	Muskogon Lake	531
371NB1A	NJ	299	207,639	O/E/TR	Great Egg Harbor Bay	299
251IB1N	IN	490	340402	GL	Lake Michigan	586
244TB2A	TX	467	324,306	O/E/TR	Laguna Madre	682
431AB73	AL	1,119	777,000	O/E/TR	Mobile River	1,837
280FB27	FL	562	390,000	O/E/TR	Tampa Bay	960
370MB8C	MS	297	206,000	R (Large)	Mississippi River	1,328
111WBQ5	WI	63	43,982	GL	Lake Superior	76
541FB50	OH	810	562,400	GL	Lake Erie	849
183PBT8	PA	145	100,694	R (Large)	Ohio River	125
462NB6T	NC	1,457	1,012,000	L	Belews Lake	2,240
412MB5Y	MI	950	660,000	GL	St. Clair River	1,260
458FB2D	FL	1,396	969,472	O/E/TR	Hillsborough Bay	1,824
414TB4D	TX	979	679,861	L	Fairfield Reservoir	1,150
495LB86	LA	380	264,000	R (Large)	Mississippi River	615
375MB7F	MN	307	213,194	R (Small)	Minnesota River	401
482WB7	WI	105	73,125	R (Small)	Rock River	50
319WB4F	WI	170	118,000	L	Lake Monona	195
428NB3V	NY	1,106	768,396	O/E/TR (Large)	Hudson River	1,200
448TB4I	TX	1,238	859,722	L	Lake Braunig	850
452MB3E	MA	1,300	902,778	O/E/TR (Small)	Taunton River	1,600
200VB79	VA	179	124,275	R (Small)	James River	250
227CB2M	CT	440	305,556	O/E/TR	Bridgeport Harbor	566
144NBN3	NY	99	68,750	O/E/TR	East River	322

Fossil Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
538PB8N	PA	795	552,000	R (Large)	Susquehanna River	1,642
206NB77	NC	395	274,000	R (Small)	Yadkin River	487
289TB66	TN	590	417,000	L	Melton Hill Resevoir	911
161IBF8	IA	116	80,666	R (Large)	Mississippi River	212
141IBT5	IN	97	67,361	GL	Lake Michigan	178
316FC4V	FL	213	147,778	L	Sewer Effluent & Lake Parker	993
232MC3B	MD	446	309,793	O/E/TR	Seneca Creek	385
333GC1M	Guam	238	165,278	O/E/TR	Pacific Ocean	210
479TC4S	TX	1,930	1,340,000	L	San Antonio River	2,200
115CCD7	CO	66	45,972	R (Small)	Colorado River	75
142NCR8	NE	97	67,000	R	Platte River	125
263MC12	MA	520	361,111	O/E/TR	Cape Cod Canal	1,120
397KC8S	KY	370	257,184	R (Large)	Ohio River	645
537FC30	FL	792	550,000	O/E/TR (Small)	Indian River	804
387NC8P	NC	342	117,600	R (Small)	Cape Fear River	870
437OC8Q	OH	1,152	800,000	R (Large)	Ohio River	1,200
131ACW7	AR	68	47,222	R (Large)	WHITE RIVER	124
336NC8W	NY	245	170,139	R (Large)	Cayuga Lake	306
533IC7T	IN	766	532,000	L	Wabash River	1,070
433TC2M	TX	1,132	786,200	O/E/TR	Upper Galveston Bay	1,740
519MC32	MD	720	500,000	O/E/TR	Patuxent River	710
117MCA7	MO	71	49,025	L	Missouri River	70
123ACP8	AL	78	54,167	R	Tombigbee River	86
255VC3N	VA	514	356,687	O/E/TR	Elizabeth River	604
535VC38	VA	786	545,486	O/E/TR (Small)	James River	1,328
484PC89	PA	376	261,000	R (Large)	Allegheny River	637
187MCB6	MN	156	108,000	L	North Blackwater Lake	140
353NC7Y	NC	269	187,000	R (Small)	Broad River	289
461IC83	IN	1,434	996,000	R (Large)	Ohio River	1,306
282IC43	IL	575	399,500	L	McDavid Branch	978
453AC87	AL	1,325	920,000	R (Large)	Tennessee River	1,332
157OCU9	OK	111	76,850	L	Comanche Reservoir	117
153OCF7	OH	108	75,000	R (Small)	Muskingum River	165
317MC5C	MI	213	148,000	GL	Detroit River	239
228CC3L	CA	440	305,556	O/E/TR	San Joaquin River	690
551PC1Q	PR	874	604,722	O/E/TR	Guayanilla Bay	1,086
120CCJ9	CT	75	52,083	L	Connecticut River	69
277IC75	IL	550	382,000	R (Small)	Chicago River--South Branch	584

Fossil Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
496FCE3	FL	156	108,000	O/E/TR (Small)	Escambia River	150
393PC7V	PA	359	249,000	R (Small)	Schuylkill River	380
407FC20	FL	919	638,000	O/E/TR	Gulf of Mexico	900
493TC60	TN	2,730	1,896,000	R	Cumberland	2,650
318FC2D	FL	213	148,000	O/E/TR	Biscayne Bay	237
365KD7M	KY	290	201,389	R (Small)	Kentucky River	196
390ID4D	IL	353	245,139	L	Lake Springfield	372
222MD5Q	MI	432	300,000	GL	Saginaw River	515
359ND7H	NC	280	194,400	R (Small)	Dan River	361
240ND3D	NY	455	315,972	O/E/TR (Large)	Hudson River	493
381WD7H	WY	193	134,000	R (Small)	North Platte River	454
512TD4K	TX	695	482,639	L	Lake Long	932
250TD4J	TX	488	338,889	L	Reservoir	818
322ND3S	NJ	221	153,516	O/E/TR (Small)	Delaware River	166
215MD7W	MD	407	282,639	R (Small)	Potomac River	576
160SDS7	SC	116	80,800	R (Small)	Waccamaw River	180
174IDA8	IA	134	92,986	R (Large)	Mississippi River	77
283ND5T	NY	576	400,000	GL	Lake Erie	586
542AE7C	AL	832	578,000	R (Small)	Coosa River	1,000
284IE70	IL	579	402,200	R (Small)	Illinois River	740
366NE1A	NY	294	204,000	O/E/TR	Barnum Island Channel	380
398TE2C	TX	370	256,944	O/E/TR	Lavaca Bay	261
104WEL8	WI	53	36,806	R (Large)	Mississippi River	53
518KE44	KY	716	497,222	L	Herrington Lake	739
223TE6C	TX	432	300,000	L	Reservoir	665
385IE7C	IN	335	232,917	R (Small)	White River	359
396NE3A	NY	368	255,833	O/E/TR	East River	599
436OE5A	OH	1,146	796,000	GL	Lake Erie	1,594
154MEU7	MS	108	75,000	R (Small)	Leaf River	68
465PE7H	PA	1,469	1,020,000	R (Small)	Delaware River	1,570
544DE32	DE	837	581,318	O/E/TR (Small)	Delaware River	705
242WE5C	WI	463	321,250	GL	Lake Michigan	770
304IEZ78	IN	187	129,715	R (Small)	West fork White River	160
204CE18	CA	381	264,800	O/E/TR	Pacific Ocean	941
119MEG8	MN	73	57,639	R (Large)	Mississippi River	195
350KE8V	KY	265	184,100	R (Large)	Ohio River	441
259PE84	PA	518	360,000	R (Large)	Monongahela River	510
547CE1L	CA	857	595,139	O/E/TR	Agua Hedionda Lagoon	958

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
299IF8N9	IN	635	440,972	R (Large)	Ohio River	402
118IFC8	IA	71	49,306	R (Large)	Mississippi River	62
122PFQ3	PA	78	54,000	O/E/TR (Small)	Delaware River	60
132NFD2	NY	87	60,000	O/E/TR	Mott Basin	106
382IF7O	IL	323	224,306	R (Small)	Chicago River--South Branch	348
216AF61	AR	412	286,100	L	Flint Creek Reservoir	559
466TF60	TX	1,470	1,020,833	Reservoir	Forest Grove Reservoir	1,500
522FF35	FL	730	507,000	O/E/TR	Caloosahatchee River	573
488MFT4	MN	101	70,000	L	Fox Lake	98
147IFA8	IN	102	70,880	R (Large)	White River	256
133PGR8	PA	88	61,111	R (Large)	Ohio River	112
320AG7R	AL	219	152,000	R (Small)	Coosa River	120
406TG4E	TN	916	636,000	L	Cumberland	1,086
169IGZ5	IN	122	84,826	GL	Lake Michigan	221
339WG8N	WI	252	175,000	R (Large)	Mississippi River	360
536IG7Z	IA	791	50,500	R (Large)	Missouri River	950
245IG7S	IA	468	325,000	R (Large)	Missouri River	644
130GGG7	GA	85	59,028	R (Small)	Chattahoochee River	90
345MG8A	MS	260	180,866	R (Large)	Mississippi River	750
530NG6T	NE	760	528,000	R	Sutherland Supply Canal	1,444
129TGM4	TX	84	58,333	L	No 4 Resevoir	84
219TG4U	TX	418	290,278	L	Gibbons Creek Reservoir	454
400VG7M	VA	373	259,000	R (Small)	New River	335
301NG22	NY	179	124,000	O/E/TR	Hempstead Harbor	218
415AG8C	AL	979	680,000	R	Warrior River	1,221
143MGT3	MD	99	68,500	O/E/TR (Small)	Patapsco River	97
254TG4M	TX	505	350,694	L	Reservoir	630
328IG8Y	IL	229	159,200	R (Large)	Mississippi River	214
112PGV3	PA	64	44,444	O/E/TR	Sch. River	192
167WGP7	WI	120	83,479	R (Small)	Lower Fox River	137
198KG73	KY	177	123,000	R (Small)	Green River	231
207AG79	AL	396	275,000	R (Small)	Black Warrior	500
184NGJ4	NY	146	101,389	L	Seneca Lake	161
489FH29	FL	2,465	1,712,014	O/E/TR	Hillsborough Bay	2,014
170SHD4	SC	126	87,450	L	Lake Robinson	185
249OH7Y	OH	485	336,806	R (Small)	Miami River	131
275GH79	GA	548	380,500	R (Small)	Coosa River	800
432TH4R	TX	1,121	778,200	L	Lake Arlington	1,315

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
155CHW2	CA	108	75,000	O/E/TR	Pacific Ocean	75
172MHQ5	MI	130	90,000	GL	Lake Huron	103
334IH8A	IN	238	165,486	R	West fork of White River	360
435GH40	GA	1,139	791,000	L	Lake Sinclair	1,735
246IH73	IL	468	325,000	R (Small)	Illinois River	228
295MH79	MO	624	433,333	R (Largel)	Missouri River	983
420CH1Z	CA	1,014	704,167	O/E/TR	Pacific Ocean	1,279
101AHM7	AK	53	36,700	R (Small)	Nenana River	75
329IH7J	IL	230	159,722	R (Small)	Illinois River	293
152FHH2	FL	108	74,951	O/E/TR	Municipal	135
423MH3S	MD	1,060	736,220	O/E/TR	Pataspsco River	983
332MH5P	MN	236	163,826	GL	St. Louis River	124
205MH81	MN	390	270,500	R	River	510
485HH24	HI	184	128,000	O/E/TR	Pacific Ocean	103
162MHS7	MN	116	80,792	R (Small)	Otter Tail River	155
490AH4X	OK	400	277,500	L	Horseshoe Lake	396
402NH30	NJ	892	620,000	O/E/TR (Small)	Hackensack River	983
179CHR1	CA	142	98,611	O/E/TR	Pacific Ocean	135
110PHD7	PA	61	42,361	R (Small)		50
256CH1Z	CA	514	356,944	O/E/TR	Ocean	880
388NH5Z	NY	346	240,000	GL	Niagara River	816
196IHS8	IL	173	120,000	R (Large)	Wabash River	167
534MI7S	MO	774	537,500	R (Large)	Missouri River	651
543FI73	FL	835	579,861	R (Small)	Indian River	610
202DI33	DE	378	262,500	O/E/TR (Small)	Indian River	432
108MJA7	MI	60	41,667	GL (Small)	Grand River	65
121MJQ7	MT	75	52,000	R (Small)	Yellowstone River	154
411MJ5B	MI	936	650,000	GL	Lake Michigan	1,440
404OJ8I	OH	904	627,876	R (Large)	Ohio River	1,869
376MJ5N	MI	323	224,028	GL	North Maumee Bay	328
315KJ8A	KY	208	144,521	R (Large)	Cumberland River	341
264WJ53	WI	523	363,400	GL	Green Bay	373
229MJ3F	MS	441	306,000	O/E/TR (Small)	Biloxi River	512
148MJJ5	MI	103	71,181	GL	Lake Macatawa	62
358MJ4D	MO	279	193,750	L	Lake Springfield	391
391SJ9Y	SC	357	247,820	O/E/TR	TL RC CNL	508
517TJ70	TN	714	496,000	R (Small)	Holston River	816
469TJ63	TN	1,601	1,112,000	R (Large)	Tennessee River	1,408

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
460IJ7D	IL	1,424	988,890	R (Small)	Desplaines River	1,189
226IJ7B	IL	438	304,167	R (Small)	Desplaines River	341
288IJ8H	IL	589	409,028	R (Large)	Ohio River	1,002
545HK20	HI	847	588,000	O/E/TR	Pacific Ocean	650
516WK8U	WV	713	495,000	R (Large)	Ohio River	630
210WK85	WV	403	280,000	R (Large)	Kanawha River	426
166KKE8	KS	120	83,403	R	Kaw River	166
362NK3L	NJ	286	198,681	O/E/TR (Small)	Hackensack River	846
124MKP6	MA	78	54,167	R (Small)	Charles River	277
386KK8H	KY	335	232,639	R (Large)	Ohio River	455
241IK63	IL	461	320,016	Reservoir	Sangchris Lake	1,182
467TK71	TN	1,495	1,038,000	R (Small)	Emory River	1,677
300TK4B	TX	639	443,900	L	Lake Cherokee	500
343GK7Q	GA	259	180,000	R (Small)	Savannah River	479
438OK82	OH	1,166	810,000	R (Large)	Ohio River	1,085
139AKQ9	AZ	96	66,667	OTHER	Canal Well	96
441KL4T	KS	1,198	832,132	L	La Cygne Reservoir	1,422
446ML72	MO	1,231	854,580	R (Large)	Missouri River	2,560
514AL4R	AR		494,000	L	Lake Catherine	753
368TL6Z	TX	294	204,215	L	Reservoir	317
526TL40	TX	742	515,278	L	Reservoir	921
185MLZ9	MO	151	104,861	R(Large)	Cooling Towers	273
337OL5I	OH	246	170,646	GL	Lake Erie	256
372IL8C	IA	299	207,800	R (Large)	Mississippi River	317
346FL2F	FL	260	180,600	O/E/TR	North Bay	384
394FL9U	FL	368	255,554	O/E/TR	Dania Cut-Off Canal	312
383NL7B	ND	330	229,167	R (Large)	Missouri River	656
175LLC6	LA	134	93,200	Reservoir	Caddo Lake	286
247LL82	LA	468	325,000	R (Large)	Mississippi River	1,251
125TLL4	TX	79	54,861	L	Ellison Creek Reserv	40
137MMJ3	ME	94	65,000	O/E/TR (Small)	Saco River	22
344RM3B	RI	259	180,000	O/E/TR	Providence River	168
341CM1K	CA	254	176,389	O/E/TR	Pacific Ocean	430
103WMC5	WI	52	35,972	GL	Lake Michigan	106
325IM4E	IL	225	156,250	L	Lake Egypt	430
463NM6W	NC	1,463	1,015,972	L	Lake Norman	2,090
487TM6W	TX	2,411	1,674,306	L	Martin Creek Reservoir	2,250
395MM5W	MI	368	255,800	GL	St Clair River	84

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
135AMA7	AR	71	49,306	R (Small)	Ouachita River	136
136GMT7	GA	91	63,200	R (Small)	Savannah River	167
193GMU3	GA	166	115,000	O/E/TR	Turtle River	115
508MA6M	MO	675	468,400	R (Large)	Mississippi River	1,035
510NM33	NJ	691	480,000	O/E/TR (Small)	Delaware River	648
214IM7Y	IL	404	280,542	R (Small)	Illinois River	560
248IMR6	IN	484	336,000	Reservoir	Turtle Creek Reservoir	1,139
363NM7V	NH	287	199,250	R (Small)	Merrimack River	474
3350M8D	OH	240	166,667	R (Large)	Ohio River	1,300
531LM1B	LA	763	529,861	O/E/TR	Miss River Gulf Outlet	918
156CMX3	CT	108	75,000	R(Large)	Connecticut River	90
323CM8Q	CT	224	155,700	R (Large)	Connecticut River	353
330KM8C	KY	233	161,638	R (Large)	Ohio River	419
309IM85	IA	197	137,000	R (Large)	Mississippi River	255
267NM47	ND	530	368,000	L	Nelson Lake	700
218MM7Y	MO	416	288,819	R (Largel)	Missouri River	46
310MM56	MI	198	137,792	GL	Detroit River	179
197GM81	GA	173	120,000	R (Small)	Flint River	125
342PM8E	PA	255	177,083	R (Large)	Monongahela River	365
481MM54	MI	2,010	1,396,000	GL and R	River Raisin and Lake Erie	3,135
474TM67	TX	1,732	1,202,778	L	Monticello Reservoir	1,880
287MM55	MO	584	405,556	L	Montrose Reservoir	510
379CM3V	CT	315	218,400	O/E/TR (Small)	Thames River	516
274TM4L	TX	547	379,861	L	Reservoir	1,354
127WML8	WV	80	55,750	R (Large)	Monongahela River	58
447MM3K	MD	1,234	857,000	O/E/TR (Small)	Potomac River	1,248
237CN1W	CA	453	314,800	O/E/TR	Morro Bay	600
445CM1X	CA	1,224	850,000	O/E/TR	Moss Landing Harbor	1,899
180MMM8	MA	143	99,306	R (Large)	Connecticut River	144
521TM42	TX	722	501,050	L	Mountian Creek Lake	810
440WM43	WV	1,184	822,000	L	Stony River	1,693
364IM7W	IA	288	199,729	R (Large)	Mississippi River	233
5490M7U	OH	864	600,000	R (Small)	Muskingum River	840
1490MB7	OK	107	74,000	R (Small)	Arkansas River	180
501MM30	MA	646	448,611	O/E/TR	Mystic River	560
114WNZ8	WV	65	45,139	R (Large)	Ohio River	123
224NN7D	NE	432	300,000	R (Large)	Missouri River	653
195WNW8	WI	167	115,972	R (Large)	Mississippi River	200

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
213CN28	CT	404	280,382	O/E/TR	New Haven Harbor	466
550MN80	MO	864	600,000	R (Large)	Mississippi River	1,200
373NN3J	NH	325	225,555	O/E/TR	Piscataqua River	422
539IN81	IL	806	560,000	R	Laws Creek/ Sandy Creek	1,288
211ON73	OH	403	280,000	R (Small)	Mahoning River	266
278LN8G	LA	555	385,231	R (Large)	Mississippi River	1,918
313IN79	IN	207	143,750	R (Small)	West fork White River	286
266NN76	NE	529	367,500	R (Large)	Missouri River	664
138TNT4	TX	95	65,972	L	Lake Weatherford	71
410NN17	NY	926	643,000	O/E/TR	Long Island Sound	1,500
502FN39	FL	648	449,974	O/E/TR (Small)	St Johns River	1,159
377CN1D	CT	312	216,667	O/E/TR	Long Island Sound	330
212OO8U	OH	403	279,861	R	Great Miami River	388
483WO5R	WI	2,148	1,492,000	GL	Lake Michigan	2,493
464TO6Q	TX	1,469	1,020,000	Reservoir	Twin Oaks Reservoir	1,710
509CO1Z	CA	685	475,694	O/E/TR	Pacific Ocean	1,516
434NO5F	NY	1,132	786,200	GL	Lake Ontario	1,740
331MO7T	MI	233	162,000	R (Small)	Grand River	330
504PP10	PR	654	451,389	O/E/TR	Boca Vieja Cove	602
292KP7U	KY	608	876,000	R(Small)	Green River	2,427
106IPT8	IN	55	38,472	R (Large)	Wabash River	36
220IP8E	IN	428	297,104	R (Large)	White River	880
421WP8P	WV	1,038	721,000	R (Large)	Ohio River	1,050
146OPP7	OH	101	70,000	R (Small)	Scioto River	100
273TP6G	TX	544	378,000	Reservoir	Brandy Branch Reservoir	700
408CP33	CA	924	642,000	O/E/TR	Sacramento/San Joaquin RI	506
449FP90	FL	1,253	870,000	O/E/TR	Intercoastal Waterway	1,254
367NP1X	NY	294	204,000	O/E/TR	Long Island Sound	380
523WP59	WI	732	508,000	GL	Lake Michigan	1,266
378PP7U	PA	314	218,000	R (Small)	Delaware River	427
324VP3L	VA	224	155,296	O/E/TR (Small)	Potomac River	313
235VP33	VA	450	312,634	O/E/TR (Small)	Potomac River	510
327CP2B	CA	226	156,944	O/E/TR	San Francisco Bay	207
311IP77	IA	205	142,361	R (Small)	Cedar River	238
399MP5M	MI	370	257,198	GL	Lake Superior	570
351KQ7S	KS	265	184,028	R (Large)	Missouri River	305
173KRH7	KY	130	90,278	R (Small)	Green River	130

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
3260R8U	OH	225	156,350	R (Large)	Ohio River	416
225IR8K	IN	436	302,800	R (Large)	Ohio River	616
113NRD7	ND	64	44,444	R (Large)	Missouri River	103
128MRQ7	MD	103	71,800	R (Small)	Potomac River	116
208TR40	TX	396	275,000	L	Lake Palo Pinto	574
457NR3K	NY	1,389	964,535	O/E/TR	East River	2,401
392TR5J	TX	357	247,917	L	Lake Lavon	345
102MRP8	MN	50	34,652	R	Mississippi	26
401CR16	CA	891	618,750	O/E/TR	Pacific Ocean	1,310
305OR81	OH	187	130,000	R (Large)	Ohio River	213
230MR52	MI	441	306,000	GL	Detroit River	540
217NR4N	NC	415	288,000	L	Mt. Island Lake	470
109MRL7	MD	61	42,210	R (Small)	Patapsco River	78
134IRA8	IA	90	62,500	R	Miss River	381
357MR8K	MN	277	192,355	R (Large)	Mississippi River	420
151KRC8	KS	105	72,917	R	Spring River	88
164WRZ8	WV	119	82,583	R (Large)	Monongahela River	137
281FR2K	FL	565	392,000	O/E/TR	Lake Worth	665
238AR8R	AR	454	315,058	R (Large)	Mississippi River	919
191WRA7	WI	164	113,889	R (Small)	Rock River	150
409NR39	NY	924	641,666	O/E/TR (Large)	Hudson River	1,185
425NR6H	NC	1,096	761,210	Reservoir	Hyco Lake	1,775
426MR81	MO	1,097	762,000	R (Large)	Mississippi River	1,340
176FSS3	FL	134	93,056	O/E/TR	St Marks	301
540TS4E	TX	807	560,500	L	Sabine Lake	2,167
511MS18	MA	692	480,556	O/E/TR	Atlantic Ocean	743
297TS4M	TX	630	437,500	L	Lake Bastrop	639
430TS4C	TX	1,117	775,694	L	FPP Lake	1,641
528PS15	PR	749	520,000	O/E/TR	Puerto Nuevo Bay	534
194FSY7	FL	167	116,000	R (Small)	St Johns River	156
252CS1K	CA	495	343,750	O/E/TR	Pacific Ocean	838
168NSE3	NH	153	106,250	O/E/TR	Piscataqua River	160
171FSV8	FL	130	90,000	R (Large)	Apalachicola River	80
314PS80	PA	207	144,000	R (Small)	Schuylkill River	228
443OS4B	OK	1,434	996,000	L	Lake Konawa	1,500
272NS3Q	NJ	542	376,112	O/E/TR	Arthur Kill	428
470KS89	KY	1,613	1,120,000	R (Large)	Ohio River	1,610
505PS8J	PA	656	455,200	R (Large)	Susquehanna River	626

Fossil Facilities						
Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
349MS5P	MI	264	183,333	GL	Lake Superior	77
239MS7C	MO	454	315,278	R (Large)	Missouri River	508
186MSG5	MN	151	105,069	GL	Lake Superior	105
165MSN4	MN	119	82,639	L	Zumbro River	106
529MS8Y	MO	749	520,000	R (Large)	Mississippi River	1,100
356IS8G	IA	276	191,600	R	River/Lake	65
355NS5A	NY	274	190,278	GL	Lake Ontario	675
354MS3N	MA	274	190,277	O/E/TR (Small)	Taunton River	125
535OS48	OK	789	548,000	L	Sooner Lake	1,096
258CS2V	CA	517	359,136	O/E/TR	San Diego Bay	696
524TS90	TX	740	514,000	O/E/TR	Houston Ship Channel	861
429MS54	MI	1,111	771,790	GL	St Clair River	1,417
181NSO7	ND	144	100,000	R (Largel)	Missouri River	202
294IS55	IN	621	430,878	GL	Lake Michigan	1,711
190LSH7	LA	158	110,000	R (Small)	Ouachita River	224
265TS49	TX	527	365,972	L	Stryker Creek Reservoir	675
369PS8H	PA	296	205,556	R (Large)	Susquehanna River	407
347FS7J	FL	261	181,000	R (Small)	Suwannee River	217
177MSN4	MN	136	94,500	L	Colby Lake	110
303MT56	MN	184	127,998	GL	Lake Superior	225
424IT8W	IN	1,066	740,000	R (Large)	Ohio River	995
492LT3B	LA	451	313,194	O/E/TR	Charenton	430
507TT6H	TN	674	468,132	R	South Fork - Holston River	194
189CTC7	CT	156	107,986	R (Small)	Thames River	181
107AF7	AR	42	29,167	R (Small)	Arkansas River	60
209TT41	TX	397	276,031	L	Lake LBJ	446
417MT4J	MO	1,002	696,000	L	Thomas Hill Lake	1,197
422TT4W	TX	1,056	733,333	L	Tradinghouse Creek Reservoir	1,383
257MT5F	MI	516	358,000	GL	Detroit River	730
361NT6S	TX	285	197,917	L	Reservoir	240
494TT6W	TX	305	211,806	Reservoir	Twin Oaks Reservoir	330
126KTR7	KY	79	55,000	R (Small)	Kentucky River	75
159IUD4	IN	113	78,472	L	St. Joseph Lake	28
306SU72	SC	190	132,000	R (Small)	Savannah River	243
192WV5	WI	165	114,800	GL	Menomonee River	280
403TV41	TX	894	620,833	L	Reservoir	1,115
308CV64	CO	194	135,000	L	Hillcrest Reservoir	186
182FVB2	FL	144	100,090	O/E/TR	Municipal	150

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
279TV6D	TX	557	386,806	R	Wells and Guadalupe River	80
454OW8S	OH	1,353	939,628	R (Large)	Ohio River	2,219
384SW7R	SC	331	230,000	R (Small)	Saluda River	424
480TW4P	TX	2,002	1,390,000	L	Smithers Lake	2,726
527IW78	IN	747	518,848	R (Large)	Wabash River	1,026
221HW17	HI	430	298,839	O/E/TR	Pacific Ocean	397
525OW8U	OH	741	514,837	R (Large)	Ohio River	1,222
298IW76	IA	634	440,278	R (Largel)	Missouri River	823
360IW8C	IN	281	195,139	R (Large)	Ohio River	693
293LW80	LA	618	429,000	R (Large)	Mississippi River	912
546IW51	IL	847	588,067	GL	Lake Michigan	976
442TW6T	TX	1,218	846,000	Reservoir	Swauano Creek Reservoir	1,674
116MWP8	MA	69	47,917	R (Large)	Connecticut River	289
105NWU3	NY	55	38,194	O/E/TR (Large)	Hudson River	74
163WWQ7	WI	118	81,900	R (Small)	Wisconsin River	135
140NWD8	NY	97	67,361	R (Large)	Susquehanna River	132
472AW6B	AL	1,645	1,560,000	R (Large)	Tennessee River	1,761
270TW6A	TX	539	374,000	Reservoir	Johnson Creek Reservoir	888
451IW9B	IL	1,296	900,000	GL	Chicago River-Sanitary Ship Canal	1,300
268SM61	SC	534	370,500	Reservoir	Back River Reservoir	656
418LW87	LA	1,002	696,000	R (Large)	Mississippi River	2,045
312WW88	WV	205	142,361	R (Large)	Ohio River	235
290IW87	IL	591	410,500	R (Large)	Mississippi River	586
158MWA5	MI	112	77,778	GL	Detroit River	73
348MW2X	ME	263	182,636	O/E/TR	Casco Bay	837
456VY34	VA	1,382	960,000	O/E/TR	York River	1,230

APPENDIX B

Plants with Independent Cost Information

Nuclear Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
100NB3E	NC	1,921	1,333,734	O/E/TR (Small)	Cape Fear River	2,060
416FC20	FL	979	680,000	O/E/TR	Gulf of Mexico	890
321CD1H	CA	2,500	1,736,111	O/E/TR	Pacific Ocean	2,298
285MD59	MI	2,369	1,645,000	GL	Lake Michigan	2,161
477ID7Y	IL	1,898	1,017,000	R (Small)	Kankakee River	1,914
145NI38	NY	2,420	1,680,484	O/E/TR (Large)	Hudson River	2,045
178VN45	VA	2,707	1,880,000	L	Lake Anna	1,956
506NO2L	NJ	1,394	968,333	O/E/TR	Barnegat Bay	630
218NS2K	NJ	3,168	2,200,000	O/E/TR (Small)	Deleware River	2,540
302CS1V	CA	2,335	1,621,528	O/E/TR	Pacific Ocean	2,150
233NS11	NH	447	310,416	O/E/TR	Atlantic Ocean	1,296
459FS1A	FL	1,403	974,600	O/E/TR	Atlantic Ocean	1,700
236VS36	VA	2,534	1,760,000	O/E/TR (Small)	James River	1,802

Fossil Facilities						
Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW
439CA1S	CA	1,181	820,139	O/E/TR	Cerritos Channel	1,950
515NA2M	NY	713	495,139	O/E/TR	Lower New York Bay	875
244TB2A	TX	467	324,306	O/E/TR	Laguna Madre	682
458FB2D	FL	1,396	969,472	O/E/TR	Hillsborough Bay	1,824
289TB66	TN	590	417,000	L	Melton Hill Resevoir	911
232MC3B	MD	446	309,793	O/E/TR	Seneca Creek	385
537FC30	FL	792	550,000	O/E/TR (Small)	Indian River	804
387NC8P	NC	342	117,600	R (Small)	Cape Fear River	870
437OC8Q	OH	1,152	800,000	R (Large)	Ohio River	1,200
461IC83	IN	1,434	996,000	R (Large)	Ohio River	1,306
453AC87	AL	1,325	920,000	R (Large)	Tennessee River	1,332
153OCF7	OH	108	75,000	R (Small)	Muskingum River	165
277IC75	IL	550	382,000	R (Small)	Chicago River--South Branch	584
493TC60	TN	2,730	1,896,000	R	Cumberland	2,650
318FC2D	FL	213	148,000	O/E/TR	Biscayne Bay	237
283ND5T	NY	576	400,000	GL	Lake Erie	586
382IF7O	IL	323	224,306	R (Small)	Chicago River--South Branch	348
522FF35	FL	730	507,000	O/E/TR	Caloosahatchee River	573
406TG4E	TN	916	636,000	L	Cumberland	1,086
275GH79	GA	548	380,500	R (Small)	Coosa River	800
423MH3S	MD	1,060	736,220	O/E/TR	Pataspsco River	983
402NH30	NJ	892	620,000	O/E/TR (Small)	Hackensack River	983
388NH5Z	NY	346	240,000	GL	Niagara River	816
517TJ70	TN	714	496,000	R (Small)	Holston River	816
469TJ63	TN	1,601	1,112,000	R (Large)	Tennessee River	1,408
460IJ7D	IL	1,424	988,890	R (Small)	Desplaines River	1,189
226IJ7B	IL	438	304,167	R (Small)	Desplaines River	341
516WK8U	WV	713	495,000	R (Large)	Ohio River	630
210WK85	WV	403	280,000	R (Large)	Kanawha River	426
241IK63	IL	461	320,016	Reservoir	Sangchris Lake	1,182
467TK71	TN	1,495	1,038,000	R (Small)	Emory River	1,677
438OK82	OH	1,166	810,000	R (Large)	Ohio River	1,085

Fossil Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
394FL9U	FL	368	255,554	O/E/TR	Dania Cut-Off Canal	312
5490M7U	OH	864	600,000	R (Small)	Muskingum River	840
483WO5R	WI	2,148	1,492,000	GL	Lake Michigan	2,493
421WP8P	WV	1,038	721,000	R (Large)	Ohio River	1,050
146OPP7	OH	101	70,000	R (Small)	Scioto River	100
408CP33	CA	924	642,000	O/E/TR	Sacramento/San Joaquin RI	506
449FP90	FL	1,253	870,000	O/E/TR	Intercoastal Waterway	1,254
281FR2K	FL	565	392,000	O/E/TR	Lake Worth	665
540TS4E	TX	807	560,500	L	Sabine Lake	2,167
194FSY7	FL	167	116,000	R (Small)	St Johns River	156
505PS8J	PA	656	455,200	R (Large)	Susquehanna River	626
424IT8W	IN	1,066	740,000	R (Large)	Ohio River	995
546IW51	IL	847	588,067	GL	Lake Michigan	976
472AW6B	AL	1,645	1,560,000	R (Large)	Tennessee River	1,761
451IW9B	IL	1,296	900,000	GL	Chicago River-Sanitary Ship Canal	1,300
348MW2X	ME	263	182,636	O/E/TR	Casco Bay	837

APPENDIX C

Plants with Completed Worksheets

Nuclear Facilities								
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**	**Region**	**Salinity**
100NB3E	NC	1,921	1,333,734	O/E/TR (Small)	Cape Fear River	2,060	MA	Brackish
416FC20	FL	979	680,000	O/E/TR	Gulf of Mexico	890	SE	Saline
321CD1H	CA	2,500	1,736,111	O/E/TR	Pacific Ocean	2,298	P	Saline
285MD59	MI	2,369	1,645,000	GL	Lake Michigan	2,161	NC	Fresh
477ID7Y	IL	1,898	1,017,000	R (Small)	Kankakee River	1,914	MW	Fresh
145NI38	NY	2,420	1,680,484	O/E/TR (Large)	Hudson River	2,045	NE	Brackish
486WK50	WI	582	404,188	GL	Lake Michigan	595	NC	Fresh
253NN5R	NY	495	343,750	GL	Lake Ontario	1,778	NE	Fresh
178VN45	VA	2,707	1,880,000	L	Lake Anna	1,956	MA	Fresh
506NO2L	NJ	1,394	968,333	O/E/TR	Barnegat Bay	630	MA	Brackish
473TP30	TX	1,681	1,167,450	O/E/TR	Galveston Bay	2,285	SC	Brackish
419WP59	WI	1,008	700,000	GL	Lake Michigan	1,365	NC	Fresh
269NR5H	NY	536	372,000	GL	Lake Ontario	581	NE	Fresh
218NS2K	NJ	3,168	2,200,000	O/E/TR (Small)	Deleware River	2,540	MA	Brackish
302CS1V	CA	2,335	1,621,528	O/E/TR	Pacific Ocean	2,150	P	Saline
233NS11	NH	447	310,416	O/E/TR	Atlantic Ocean	1,296	NE	Saline
459FS1A	FL	1,403	974,600	O/E/TR	Atlantic Ocean	1,700	SE	Saline
236VS36	VA	2,534	1,760,000	O/E/TR (Small)	James River	1,802	MA	Brackish
520SV40	SC	720	500,000	L	Parr Reservoir	1,100	MA	Fresh

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW	Salinity
439CA1S	CA	1,181	820,139	O/E/TR	Cerritos Channel	1,950	Brackish
276TA88	TN	549	381,000	R (Large)	Mississippi River	864	Fresh
271WA8S	WI	540	375,000	R (Large)	Mississippi River	605	Fresh
450FA29	FL	1,287	894,000	O/E/TR	Anclote River	1,030	Brackish
338OA5C	OH	252	175,000	GL	Lake Erie	256	Fresh
380NA4E	NC	316	219,600	L	Lake Julian (Powell Creek)	837	Fresh
296OA52	OH	625	434,000	GL	Lake Erie	766	Fresh
251IB1N	IN	490	340402	GL	Lake Michigan	586	Fresh
431AB73	AL	1,119	777,000	O/E/TR	Mobile River	1,837	Brackish
280FB27	FL	562	390,000	O/E/TR	Tampa Bay	960	Brackish
370MB8C	MS	297	206,000	R (Large)	Mississippi River	1,328	Fresh
541FB50	OH	810	562,400	GL	Lake Erie	849	Fresh
462NB6T	NC	1,457	1,012,000	L	Belews Lake	2,240	Fresh
495LB86	LA	380	264,000	R (Large)	Mississippi River	615	Fresh
200VB79	VA	179	124,275	R (Small)	James River	250	Fresh
227CB2M	CT	440	305,556	O/E/TR	Bridgeport Harbor	566	Saline
538PB8N	PA	795	552,000	R (Large)	Susquehanna River	1,642	Fresh
206NB77	NC	395	274,000	R (Small)	Yadkin River	487	Fresh
161IBF8	IA	116	80,666	R (Large)	Mississippi River	212	Fresh
397KC8S	KY	370	257,184	R (Large)	Ohio River	645	Fresh
537FC30	FL	792	550,000	O/E/TR (Small)	Indian River	804	Brackish
387NC8P	NC	342	117,600	R (Small)	Cape Fear River	870	Fresh
437OC8Q	OH	1,152	800,000	R (Large)	Ohio River	1,200	Fresh
433TC2M	TX	1,132	786,200	O/E/TR	Upper Galveston Bay	1,740	Brackish
117MCA7	MO	71	49,025	L	Missouri River	70	Fresh
255VC3N	VA	514	356,687	O/E/TR	Elizabeth River	604	Brackish
535VC38	VA	786	545,486	O/E/TR (Small)	James River	1,328	Brackish
484PC89	PA	376	261,000	R (Large)	Allegheny River	637	Fresh
187MCB6	MN	156	108,000	L	North Blackwater Lake	140	Fresh
353NC7Y	NC	269	187,000	R (Small)	Broad River	289	Fresh
461IC83	IN	1,434	996,000	R (Large)	Ohio River	1,306	Fresh
157OCU9	OK	111	76,850	L	Comanche Reservoir	117	Fresh
153OCF7	OH	108	75,000	R (Small)	Muskingum River	165	Fresh
228CC3L	CA	440	305,556	O/E/TR	San Joaquin River	690	Brackish
277IC75	IL	550	382,000	R (Small)	Chicago River--South Branch	584	Fresh
496FCE3	FL	156	108,000	O/E/TR (Small)	Escambia River	150	Brackish
393PC7V	PA	359	249,000	R (Small)	Schuylkill River	380	Fresh
407FC20	FL	919	638,000	O/E/TR	Gulf of Mexico	900	Saline

Fossil Facilities

Plant ID	State	MGD	GPM	Water Type	Source Waterbody	MW	Salinity
318FC2D	FL	213	148,000	O/E/TR	Biscayne Bay	237	Brackish
359ND7H	NC	280	194,400	R (Small)	Dan River	361	Fresh
160SDS7	SC	116	80,800	R (Small)	Waccamaw River	180	Fresh
542AE7C	AL	832	578,000	R (Small)	Coosa River	1,000	Fresh
436OE5A	OH	1,146	796,000	GL	Lake Erie	1,594	Fresh
154MEU7	MS	108	75,000	R (Small)	Leaf River	68	Fresh
465PE7H	PA	1,469	1,020,000	R (Small)	Delaware River	1,570	Fresh
544DE32	DE	837	581,318	O/E/TR (Small)	Delaware River	705	Brackish
204CE18	CA	381	264,800	O/E/TR	Pacific Ocean	941	Saline
119MEG8	MN	73	57,639	R (Large)	Mississippi River	195	Fresh
259PE84	PA	518	360,000	R (Large)	Monongahela River	510	Fresh
547CE1L	CA	857	595,139	O/E/TR	Agua Hedionda Lagoon	958	Brackish
122PFQ3	PA	78	54,000	O/E/TR (Small)	Delaware River	60	Brackish
382IF7O	IL	323	224,306	R (Small)	Chicago River--South Branch	348	Fresh
216AF61	AR	412	286,100	L	Flint Creek Reservoir	559	Fresh
522FF35	FL	730	507,000	O/E/TR	Caloosahatchee River	573	Brackish
320AG7R	AL	219	152,000	R (Small)	Coosa River	120	Fresh
339WG8N	WI	252	175,000	R (Large)	Mississippi River	360	Fresh
345MG8A	MS	260	180,866	R (Large)	Mississippi River	750	Fresh
400VG7M	VA	373	259,000	R (Small)	New River	335	Fresh
415AG8C	AL	979	680,000	R	Warrior River	1,221	Fresh
198KG73	KY	177	123,000	R (Small)	Green River	231	Fresh
207AG79	AL	396	275,000	R (Small)	Black Warrior	500	Fresh
170SHD4	SC	126	87,450	L	Lake Robinson	185	Fresh
275GH79	GA	548	380,500	R (Small)	Coosa River	800	Fresh
432TH4R	TX	1,121	778,200	L	Lake Arlington	1,315	Fresh
155CHW2	CA	108	75,000	O/E/TR	Pacific Ocean	75	Saline
420CH1Z	CA	1,014	704,167	O/E/TR	Pacific Ocean	1,279	Saline
332MH5P	MN	236	163,826	GL	St. Louis River	124	Fresh
485HH24	HI	184	128,000	O/E/TR	Pacific Ocean	103	Saline
402NH30	NJ	892	620,000	O/E/TR (Small)	Hackensack River	983	Brackish
179CHR1	CA	142	98,611	O/E/TR	Pacific Ocean	135	Saline
256CH1Z	CA	514	356,944	O/E/TR	Ocean	880	Saline
202DI33	DE	378	262,500	O/E/TR (Small)	Indian River	432	Brackish
121MJQ7	MT	75	52,000	R (Small)	Yellowstone River	154	Fresh
411MJ5B	MI	936	650,000	GL	Lake Michigan	1,440	Fresh
404OJ8I	OH	904	627,876	R (Large)	Ohio River	1,869	Fresh
229MJ3F	MS	441	306,000	O/E/TR (Small)	Biloxi River	512	Brackish

Fossil Facilities							
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**	**Salinity**
391SJ9Y	SC	357	247,820	O/E/TR	TL RC CNL	508	Brackish
460IJ7D	IL	1,424	988,890	R (Small)	Desplaines River	1,189	Fresh
226IJ7B	IL	438	304,167	R (Small)	Desplaines River	341	Fresh
545HK20	HI	847	588,000	O/E/TR	Pacific Ocean	650	Saline
516WK8U	WV	713	495,000	R (Large)	Ohio River	630	Fresh
210WK85	WV	403	280,000	R (Large)	Kanawha River	426	Fresh
241IK63	IL	461	320,016	Reservoir	Sangchris Lake	1,182	Fresh
300TK4B	TX	639	443,900	L	Lake Cherokee	500	Fresh
343GK7Q	GA	259	180,000	R (Small)	Savannah River	479	Fresh
438OK82	OH	1,166	810,000	R (Large)	Ohio River	1,085	Fresh
346FL2F	FL	260	180,600	O/E/TR	North Bay	384	Brackish
394FL9U	FL	368	255,554	O/E/TR	Dania Cut-Off Canal	312	Brackish
383NL7B	ND	330	229,167	R (Large)	Missouri River	656	Fresh
175LLC6	LA	134	93,200	Reservoir	Caddo Lake	286	Fresh
247LL82	LA	468	325,000	R (Large)	Mississippi River	1,251	Fresh
344RM3B	RI	259	180,000	O/E/TR	Providence River	168	Brackish
341CM1K	CA	254	176,389	O/E/TR	Pacific Ocean	430	Saline
463NM6W	NC	1,463	1,015,972	L	Lake Norman	2,090	Fresh
136GMT7	GA	91	63,200	R (Small)	Savannah River	167	Fresh
193GMU3	GA	166	115,000	O/E/TR	Turtle River	115	Brackish
510NM33	NJ	691	480,000	O/E/TR (Small)	Delaware River	648	Brackish
248IMR6	IN	484	336,000	Reservoir	Turtle Creek Reservoir	1,139	Fresh
323CM8Q	CT	224	155,700	R (Large)	Connecticut River	353	Fresh
330KM8C	KY	233	161,638	R (Large)	Ohio River	419	Fresh
267NM47	ND	530	368,000	L	Nelson Lake	700	Fresh
197GM81	GA	173	120,000	R (Small)	Flint River	125	Fresh
481MM54	MI	2,010	1,396,000	GL and R	River Raisin and Lake Erie	3,135	Fresh
379CM3V	CT	315	218,400	O/E/TR (Small)	Thames River	516	Brackish
127WML8	WV	80	55,750	R (Large)	Monongahela River	58	Fresh
237CN1W	CA	453	314,800	O/E/TR	Morro Bay	600	Saline
445CM1X	CA	1,224	850,000	O/E/TR	Moss Landing Harbor	1,899	Saline
521TM42	TX	722	501,050	L	Mountian Creek Lake	810	Fresh
440WM43	WV	1,184	822,000	L	Stony River	1,693	Fresh
5490M7U	OH	864	600,000	R (Small)	Muskingum River	840	Fresh
497PN7O	PA	253	176,000	R (Small)	Beaver River	348	Fresh
213CN28	CT	404	280,382	O/E/TR	New Haven Harbor	466	Brackish
550MN80	MO	864	600,000	R (Large)	Mississippi River	1,200	Fresh
211ON73	OH	403	280,000	R (Small)	Mahoning River	266	Fresh

Fossil Facilities							
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**	**Salinity**
278LN8G	LA	555	385,231	R (Large)	Mississippi River	1,918	Fresh
502FN39	FL	648	449,974	O/E/TR (Small)	St Johns River	1,159	Brackish
483WO5R	WI	2,148	1,492,000	GL	Lake Michigan	2,493	Fresh
509CO1Z	CA	685	475,694	O/E/TR	Pacific Ocean	1,516	Saline
434NO5F	NY	1,132	786,200	GL	Lake Ontario	1,740	Fresh
421WP8P	WV	1,038	721,000	R (Large)	Ohio River	1,050	Fresh
146OPP7	OH	101	70,000	R (Small)	Scioto River	100	Fresh
273TP6G	TX	544	378,000	Reservoir	Brandy Branch Reservoir	700	Fresh
408CP33	CA	924	642,000	O/E/TR	Sacramento/San Joaquin RI	506	Brackish
449FP90	FL	1,253	870,000	O/E/TR	Intercoastal Waterway	1,254	Brackish
523WP59	WI	732	508,000	GL	Lake Michigan	1,266	Fresh
378PP7U	PA	314	218,000	R (Small)	Delaware River	427	Fresh
324VP3L	VA	224	155,296	O/E/TR (Small)	Potomac River	313	Brackish
327CP2B	CA	226	156,944	O/E/TR	San Francisco Bay	207	Brackish
399MP5M	MI	370	257,198	GL	Lake Superior	570	Fresh
3260R8U	OH	225	156,350	R (Large)	Ohio River	416	Fresh
401CR16	CA	891	618,750	O/E/TR	Pacific Ocean	1,310	Saline
305OR81	OH	187	130,000	R (Large)	Ohio River	213	Fresh
217NR4N	NC	415	288,000	L	Mt. Island Lake	470	Fresh
281FR2K	FL	565	392,000	O/E/TR	Lake Worth	665	Brackish
238AR8R	AR	454	315,058	R (Large)	Mississippi River	919	Fresh
540TS4E	TX	807	560,500	L	Sabine Lake	2,167	Fresh
252CS1K	CA	495	343,750	O/E/TR	Pacific Ocean	838	Saline
314PS80	PA	207	144,000	R (Small)	Schuylkill River	228	Fresh
272NS3Q	NJ	542	376,112	O/E/TR	Arthur Kill	428	Brackish
505PS8J	PA	656	455,200	R (Large)	Susquehanna River	626	Fresh
258CS2V	CA	517	359,136	O/E/TR	San Diego Bay	696	Saline
524TS90	TX	740	514,000	O/E/TR	Houston Ship Channel	861	Brackish
429MS54	MI	1,111	771,790	GL	St Clair River	1,417	Fresh
181NSO7	ND	144	100,000	R (Largel)	Missouri River	202	Fresh
294IS55	IN	621	430,878	GL	Lake Michigan	1,711	Fresh
190LSH7	LA	158	110,000	R (Small)	Ouachita River	224	Fresh
347FS7J	FL	261	181,000	R (Small)	Suwannee River	217	Fresh
177MSN4	MN	136	94,500	L	Colby Lake	110	Fresh
303MT56	MN	184	127,998	GL	Lake Superior	225	Fresh
424IT8W	IN	1,066	740,000	R (Large)	Ohio River	995	Fresh
417MT4J	MO	1,002	696,000	L	Thomas Hill Lake	1,197	Fresh
126KTR7	KY	79	55,000	R (Small)	Kentucky River	75	Fresh

Fossil Facilities							
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**	**Salinity**
306SU72	SC	190	132,000	R (Small)	Savannah River	243	Fresh
403TV41	TX	894	620,833	L	Reservoir	1,115	Fresh
454OW8S	OH	1,353	939,628	R (Large)	Ohio River	2,219	Fresh
221HW17	HI	430	298,839	O/E/TR	Pacific Ocean	397	Saline
525OW8U	OH	741	514,837	R (Large)	Ohio River	1,222	Fresh
293LW80	LA	618	429,000	R (Large)	Mississippi River	912	Fresh
546IW51	IL	847	588,067	GL	Lake Michigan	976	Fresh
442TW6T	TX	1,218	846,000	Reservoir	Swauano Creek Reservoir	1,674	Fresh
270TW6A	TX	539	374,000	Reservoir	Johnson Creek Reservoir	888	Fresh
451IW9B	IL	1,296	900,000	GL	Chicago River-Sanitary Ship Canal	1,300	Fresh
268SM61	SC	534	370,500	Reservoir	Back River Reservoir	656	Fresh
418LW87	LA	1,002	696,000	R (Large)	Mississippi River	2,045	Fresh
348MW2X	ME	263	182,636	O/E/TR	Casco Bay	837	Brackish
456VY34	VA	1,382	960,000	O/E/TR	York River	1,230	Brackish

APPENDIX D

Plants for which Site-specific Analyses Were Performed

Nuclear Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
513SH4W	SC	740	514,100	L	Lake Robinson	700
218NS2K	NJ	3,168	2,200,000	O/E/TR (Small)	Delaware River	2540
477ID7Y	IL	1,898	1,318,056	R (Small)	Kankakee River	1,914
486WK50	WI	582	404,188	GL	Lake Michigan	595
419WP59	WI	1,008	700,000	GL	Lake Michigan	1,365
269NR5H	NY	536	372,000	GL	Lake Ontario	581
233NS11	NH	447	310,417	O/E/TR	Atlantic Ocean	1,296
302CS1V	CA	2,335	1,621,528	O/E/TR	Pacific Ocean	2,150
178VN45	VA	2,707	1,880,000	L	Lake Anna	1,956
459FS1A	FL	1,403	974,600	O/E/TR	Atlantic Ocean	1,700

Fossil Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
439CA1S	CA	1,181	820,139	O/E/TR	Cerritos Channel	1,950
271WA8S	WI	540	375,000	R (Large)	Mississippi River	605
338OA5C	OH	252	175,000	GL	Lake Erie	256
380NA4E	NC	316	219,600	L	Lake Julian (Powell Creek)	837
296OA52	OH	625	434,000	GL	Lake Erie	766
251IB1N	IN	490	340402	GL	Lake Michigan	586
541FB50	OH	810	562,500	GL	Lake Erie	849
495LB86	LA	380	264,000	R (Large)	Mississippi River	615
200VB79	VA	179	124,275	R (Small)	James River	250
538PB8N	PA	795	552,000	R (Large)	Susquehanna River	1,642
387NC8P	NC	342	117,600	R (Small)	Cape Fear River	870
437OC8Q	OH	1,152	800,000	R (Large)	Ohio River	1,200
433TC2M	TX	1,132	786,200	O/E/TR	Upper Galveston Bay	1,740
117MCA7	MO	71	49,025	L	Missouri River	70
535VC38	VA	786	545,486	O/E/TR (Small)	James River	1,328
484PC89	PA	376	261,000	R (Large)	Allegheny River	637
187MCB6	MN	156	108,000	L	North Blackwater Lake	140
228CC3L	CA	440	305,556	O/E/TR	San Joaquin River	690
277IC75	IL	550	382,000	R (Small)	Chicago River--South Branch	584
393PC7V	PA	359	249,000	R (Small)	Schuylkill River	380
318FC2D	FL	213	148,000	O/E/TR	Biscayne Bay	237
160SDS7	SC	116	80,800	R (Small)	Waccamaw River	180
283ND5T	NY	576	400,000	GL	Lake Erie	586
436OE5A	OH	1,146	795,833	GL	Lake Erie	1,594
465PE7H	PA	1,469	1,020,000	R (Small)	Delaware River	1,570
204CE18	CA	381	264,800	O/E/TR	Pacific Ocean	941
119MEG8	MN	73	57,639	R (Large)	Mississippi River	195
547CE1L	CA	857	595,139	O/E/TR	Agua Hedionda Lagoon	958
122PFQ3	PA	78	54,000	O/E/TR (Small)	Delaware River	60
382IF7O	IL	323	224,306	R (Small)	Chicago River--South Branch	348
339WG8N	WI	252	175,000	R (Large)	Mississippi River	360
345MG8A	MS	260	180,866	R (Large)	Mississippi River	750
198KG73	KY	177	123,000	R (Small)	Green River	231
170SHD4	SC	126	87,450	L	Lake Robinson	185
275GH79	GA	548	380,500	R (Small)	Coosa River	800
155CHW2	CA	108	75,000	O/E/TR	Pacific Ocean	75
172MHQ5	MI	130	90,000	GL	Lake Huron	103
420CH1Z	CA	1,014	704,167	O/E/TR	Pacific Ocean	1,279

Fossil Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
332MH5P	MN	236	163,826	GL	St. Louis River	124
402NH30	NJ	892	620,000	O/E/TR (Small)	Hackensack River	983
256CH1Z	CA	514	356,944	O/E/TR	Ocean	880
391SJ9Y	SC	357	247,820	O/E/TR	TL RC CNL	508
226IJ7B	IL	438	304,167	R (Small)	Desplaines River	341
516WK8U	WV	713	495,000	R (Large)	Ohio River	630
210WK85	WV	403	280,000	R (Large)	Kanawha River	426
300TK4B	TX	639	443,900	L	Lake Cherokee	500
438OK82	OH	1,166	810,000	R (Large)	Ohio River	1,085
337OL5I	OH	246	170,646	GL	Lake Erie	256
346FL2F	FL	260	180,600	O/E/TR	North Bay	384
383NL7B	ND	330	229,167	R (Large)	Missouri River	656
175LLC6	LA	134	93,200	Reservoir	Caddo Lake	286
341CM1K	CA	254	176,389	O/E/TR	Pacific Ocean	430
463NM6W	NC	1,463	1,015,972	L	Lake Norman	2,090
136GMT7	GA	91	63,200	R (Small)	Savannah River	167
193GMU3	GA	166	115,000	O/E/TR	Turtle River	115
510NM33	NJ	691	480,000	O/E/TR (Small)	Delaware River	648
323CM8Q	CT	224	155,700	R (Large)	Connecticut River	353
330KM8C	KY	233	161,638	R (Large)	Ohio River	419
267NM47	ND	530	368,000	L	Nelson Lake	700
197GM81	GA	173	120,000	R (Small)	Flint River	125
481MM54	MI	2,010	1,396,000	GL and R	River Raisin and Lake Erie	3,135
379CM3V	CT	315	218,400	O/E/TR (Small)	Thames River	516
447MM3K	MD	1,234	857,000	O/E/TR (Small)	Potomac River	1,248
237CN1W	CA	453	314,800	O/E/TR	Morro Bay	600
445CM1X	CA	1,224	850,000	O/E/TR	Moss Landing Harbor	1,899
440WM43	WV	1,184	822,000	L	Stony River	1,693
5490M7U	OH	864	600,000	R (Small)	Muskingum River	840
497PN7O	PA	253	176,000	R (Small)	Beaver River	348
550MN80	MO	864	600,000	R (Large)	Mississippi River	1,200
211ON73	OH	403	280,000	R (Small)	Mahoning River	266
483WO5R	WI	2,148	1,492,000	GL	Lake Michigan	2,493
509CO1Z	CA	685	475,694	O/E/TR	Pacific Ocean	1,516
434NO5F	NY	1,132	786,200	GL	Lake Ontario	1,740
421WP8P	WV	1,038	721,000	R (Large)	Ohio River	1,050
146OPP7	OH	101	70,000	R (Small)	Scioto River	100
273TP6G	TX	544	378,000	Reservoir	Brandy Branch Reservoir	700

Fossil Facilities						
Plant ID	**State**	**MGD**	**GPM**	**Water Type**	**Source Waterbody**	**MW**
408CP33	CA	924	642,000	O/E/TR	Sacramento/San Joaquin RI	506
449FP90	FL	1,253	870,000	O/E/TR	Intercoastal Waterway	1,254
378PP7U	PA	314	218,000	R (Small)	Delaware River	427
327CP2B	CA	226	156,944	O/E/TR	San Francisco Bay	207
3260R8U	OH	225	156,250	R (Large)	Ohio River	416
401CR16	CA	891	618,750	O/E/TR	Pacific Ocean	1,310
305OR81	OH	187	130,000	R (Large)	Ohio River	213
281FR2K	FL	565	392,000	O/E/TR	Lake Worth	665
540TS4E	TX	807	560,500	L	Sabine Lake	2,167
252CS1K	CA	495	343,750	O/E/TR	Pacific Ocean	838
314PS80	PA	207	144,000	R (Small)	Schuylkill River	228
272NS3Q	NJ	542	376,112	O/E/TR	Arthur Kill	428
505PS8J	PA	656	455,200	R (Large)	Susquehanna River	626
258CS2V	CA	517	359,136	O/E/TR	San Diego Bay	696
524TS90	TX	740	513,889	O/E/TR	Houston Ship Channel	861
429MS54	MI	1,111	771,790	GL	St Clair River	1,417
181NSO7	ND	144	100,000	R (Largel)	Missouri River	202
347FS7J	FL	261	181,000	R (Small)	Suwannee River	217
177MSN4	MN	136	94,500	L	Colby Lake	110
303MT56	MN	184	127,998	GL	Lake Superior	225
424IT8W	IN	1,066	740,000	R (Large)	Ohio River	995
126KTR7	KY	79	55,000	R (Small)	Kentucky River	75
306SU72	SC	190	132,000	R (Small)	Savannah River	243
454OW8S	OH	1,353	939,628	R (Large)	Ohio River	2,219
480TW4P	TX	2,002	1,390,278	L	Smithers Lake	2,726
525OW8U	OH	741	514,837	R (Large)	Ohio River	1,222
293LW80	LA	618	429,000	R (Large)	Mississippi River	912
442TW6T	TX	1,218	846,000	Reservoir	Swauano Creek Reservoir	1,674
270TW6A	TX	539	374,000	Reservoir	Johnson Creek Reservoir	888
451IW9B	IL	1,296	900,000	GL	Chicago River-Sanitary Ship Canal	1,300
268SM61	SC	534	370,500	Reservoir	Back River Reservoir	656
348MW2X	ME	263	182,636	O/E/TR	Casco Bay	837

No.	State	MW	Flow (MGD)	Water Type	Fuel Type	Selected for Analysis	Facility Name
Wksht-1	CA	2,130	1,152.0	O/E/TR	Fossil	x	Alamitos Generating Station
Wksht-2	WV	292	221.8	R (Small)	Fossil	x	Albright
Wksht-3	NC	1,145	785.3	L	Fossil		Allen Steam Plant
Wksht-4	WI	186	181.6	R (Large)	Fossil	x	Alma/Magett
Wksht-5	FL	993	2,865.1	O/E/TR	Fossil		Anclote
Wksht-6	MS	750	261.0		Fossil	x	Andrus
Wksht-7	NY	841	652.8	O/E/TR	Fossil		Arthur Kill Generating Station
Wksht-8	OH	420	1,017.3	GL	Fossil	x	Ashtabula
Wksht-9	NC	837	316.2	L	Fossil	x	Ashville
Wksht-10	OH	755	1,608.7	GL	Fossil		Avon Lake
Wksht-11	IN	511	492.0	R	Fossil	x	Bailly
Wksht-12	AL	2,520	1,119.0	R (Small)	Fossil		Barry Steam Electric Generating Plant
Wksht-13	FL	631	158.4	O/E/TR	Fossil		Bartow
Wksht-14	MS	1,230	592.7	R (Large)	Fossil		Baxter Wilson
Wksht-15	OH	647	742.6	GL	Fossil		Bay Shore
Wksht-16	NC	2,270	1,459.4	L	Fossil		Belews Creek
Wksht-17	LA	1,730	361.9	R (Large)	Fossil	x	Big Cajun 2
Wksht-18	MA	1,545	1,316.5	O/E/TR (Small)	Fossil		Brayton Point
Wksht-19	VA	227	168.0	R (Small)	Fossil	x	Bremo Bluff
Wksht-20	CT	515	439.5	O/E/TR	Fossil		Bridgeport Station
Wksht-21	PA	1,456	749.1	R (Large)	Fossil		Brunner Island
Wksht-22	NC	1,838	1,796.8	O/E/TR (Small)	Nuclear		Brunswick
Wksht-23	NC	462	394.3	R (Small)	Fossil		Buck
Wksht-24	KY	577	480.9	R (Large)	Fossil		Cane Run
Wksht-25	FL	801	792.4	O/E/TR (Small)	Fossil		Cape Canaveral
Wksht-26	NC	400	255.3	R (Small)	Fossil	x	Cape Fear
Wksht-27	OH	1,815	1,153.0	R (Large)	Fossil		Cardinal
Wksht-28	TX	2,258	1,454.2	O/E/TR	Fossil	x	Cedar Bayou - Units 1,2 & 4
Wksht-29	MO	59	210.1	R (Small)	Fossil	x	Chamois
Wksht-30	VA	710	513.8	O/E/TR	Fossil		Chesapeake
Wksht-31	VA	1,631	846.0	O/E/TR (Small)	Fossil	x	Chesterfield
Wksht-32	PA	580	358.7	R (Large)	Fossil	x	Cheswick Power Plant
Wksht-33	MN	918	155.1	L	Fossil	x	Clay Boswell Energy Center
Wksht-34	NC	760	262.4	R (Small)	Fossil		Cliffside
Wksht-35	IN	1,196	1,314.6	R (Large)	Fossil		Clifty Creek
Wksht-36	IL	1,052	818.9	L	Nuclear		Clinton
Wksht-37	OK	117	111.0		Fossil		Comanche
Wksht-38	OH	1,925	516.4	R (Small)	Fossil		Conesville
Wksht-39	CA	672	439.5	O/E/TR	Fossil	x	Contra Costa
Wksht-40	IL	705	552.6	R (Small)	Fossil	x	Crawford
Wksht-41	FL	1,020	274.0	O/E/TR (Small)	Fossil		Crist
Wksht-42	PA	348	316.7	R (Small)	Fossil	x	Cromby Generating Station
Wksht-43	FL	3,140	1,907.3	O/E/TR	Mixed		Crystal River 1, 2 & 3
Wksht-44	FL	206	262.4	O/E/TR	Fossil	x	Cutler
Wksht-45	NC	361	279.9	R (Small)	Fossil		Dan River
Wksht-46	CA	2,174	2,533.6	O/E/TR	Nuclear		Diablo Canyon
Wksht-47	SC	170	250.8	R (Small)	Fossil	x	Dolphus M Grainger
Wksht-48	IL	1,700	1,464.5	R (Small)	Nuclear	x	Dresden
Wksht-49	NY	586	276.5	GL	Fossil	x	Dunkirk Generating Station
Wksht-50	AL	1,897	831.2	R (Small)	Fossil		E C Gaston

Table D: Plants with Worksheets/Selected for Analysis

No.	State	MW	Flow (MGD)	Water Type	Fuel Type	Selected for Analysis	Facility Name
Wksht-51	OH	1,257	1,158.8	GL	Fossil		Eastlake
Wksht-52	MS	67	108.0	R (Small)	Fossil		Eaton
Wksht-53	PA	1,408	1,379.2	R (Small)	Fossil	x	Eddystone Generating Station
Wksht-54	DE	718	837.0	O/E/TR (Small)	Fossil		Edge Moor Power Plant
Wksht-55	CA	941	573.9	O/E/TR	Fossil		El Segundo Power
Wksht-56	MN	38	82.1	R (Large)	Fossil	x	Elk River
Wksht-57	PA	474	884.6	R (Large)	Fossil		Elrama Power Plant
Wksht-58	CA	958	775.6	O/E/TR	Fossil	x	Encina
Wksht-59	PA		77.8	O/E/TR (Small)	Fossil	x	Fairless Hills Generating Station
Wksht-60	IL	523	301.8	R (Small)	Fossil	x	Fisk Street
Wksht-61	AR		412.0				Flint Creek
Wksht-62	FL	2,415	562.9	O/E/TR	Fossil		Fort Myers
Wksht-63	AL	130	170.6	R (Small)	Fossil		Gadsden
Wksht-64	WI	356	244.3	R (Large)	Fossil	x	Genoa
Wksht-65	MS	741	256.1	R (Large)	Fossil		Gerald Andrus
Wksht-66	VA	325	345.8	R (Small)	Fossil		Glen Lyn
Wksht-67	AL	1,235	1,063.2	R	Fossil		Gorgas
Wksht-68	KY	207	177.7	R (Small)	Fossil	x	Green River
Wksht-69	AL	1,249	395.5	R (Small)	Fossil		Greene County
Wksht-70	SC	185	125.0		Fossil	x	H.B. Robinson (F)
Wksht-71	SC	700	740.0		Nuclear		H.B. Robinson (N)
Wksht-72	GA	846	467.9	R (Small)	Fossil	x	Hammond
Wksht-73	TX	1,421	1,279.7	L	Fossil		Handley
Wksht-74	CA	509	108.0	O/E/TR	Fossil	x	Harbor
Wksht-75	GA	1,607	1,142.7	L	Fossil		Harllee Branch
Wksht-76	CA	2,025	256.3	O/E/TR	Fossil	x	Haynes
Wksht-77	MN	100	235.9	GL	Fossil	x	Hibbard Energy Center
Wksht-78	HI	100	186.1	O/E/TR	Fossil		Honolulu
Wksht-79	NJ	1,052	893.2	O/E/TR (Small)	Fossil		Hudson Generating Station
Wksht-80	CA	1,037	506.9	O/E/TR	Fossil	x	Huntington Beach LLC
Wksht-81	DE	797	374.9	O/E/TR (Small)	Fossil		Indian River Generating Station
Wksht-82	MI	315	345.1	GL	Fossil		J C Weadock
Wksht-83	MT	158	75.0	R (Small)	Fossil		J E Corette Plant
Wksht-84	MI	1,448	886.7	GL	Fossil		J H Campbell
Wksht-85	MS	998	491.2	O/E/TR (Small)	Fossil		Jack Watson
Wksht-86	SC	526	140.9	O/E/TR	Fossil	x	Jefferies
Wksht-87	IL	1,036	1,305.6	R (Small)	Fossil		Joliet 29
Wksht-88	IL	429	374.9	R (Small)	Fossil	x	Joliet 9
Wksht-89	HI	582	859.6	O/E/TR	Fossil		Kahe
Wksht-90	WV	600	690.3	R (Large)	Fossil		Kammer
Wksht-91	WV	400	393.0	R (Large)	Fossil		Kanawha River
Wksht-92	WI	556	577.2	GL	Nuclear	x	Kewaunee
Wksht-93	IL	1,319	1,025.0		Fossil		Kincaid
Wksht-94	TX	486	569.4	L	Fossil	x	Knox Lee
Wksht-95	GA	333	230.7	R (Small)	Fossil		Kraft
Wksht-96	OH	986	1,095.5	R (Large)	Fossil		Kyger Creek
Wksht-97	OH	249	623.1	GL	Fossil	x	Lake Shore
Wksht-98	FL	864	274.0	O/E/TR	Fossil	x	Lansing Smith
Wksht-99	FL	1,863	587.0	O/E/TR	Fossil		Lauderdale
Wksht-100	ND	669	332.9	R (Small)	Fossil	x	Leland Olds Station

Table D: Plants with Worksheets/Selected for Analysis (cont.)

No.	State	MW	Flow (MGD)	Water Type	Fuel Type	Selected for Analysis	Facility Name
Wksht-101	LA	269	134.2	R	Fossil	x	Lieberman
Wksht-102	LA	1,198	933.9	R (Large)	Fossil		Little Gypsy
Wksht-103	RI	515		O/E/TR	Fossil		Manchester Street Station
Wksht-104	CA	560	126.0	O/E/TR	Fossil		Mandalay
Wksht-105	NC	2,090	1,463.0	L	Fossil	x	Marshall
Wksht-106	GA	814	89.8	R (Small)	Fossil	x	McIntosh
Wksht-107	GA	538	139.6	O/E/TR	Fossil	x	McManus
Wksht-108	NJ	739	703.2	O/E/TR (Small)	Fossil		Mercer Generating Station
Wksht-109	IN		483.4		Fossil		Merom
Wksht-110	CT	837	284.4	R (Large)	Fossil	x	Middletown
Wksht-111	KY	1,472	215.9	R (Large)	Fossil	x	Mill Creek
Wksht-112	ND	705	530.0	L	Fossil	x	Milton R Young
Wksht-113	GA	288	230.7	R (Small)	Fossil	x	Mitchell
Wksht-114	MI	3,129	2,013.9	GL and R	Fossil	x	Monroe
Wksht-115	CT	496	314.8	O/E/TR (Small)	Fossil	x	Montville Station
Wksht-116	WV	68	2,365.2	R (Large)	Fossil	x	Morgantown
Wksht-117	CA	999	725.2	O/E/TR	Fossil		Morro Bay Power Plant
Wksht-118	CA	2,498	863.5	O/E/TR	Fossil	x	Moss Landing Power Plant
Wksht-119	TX	890	1,010.2	L	Fossil		Mountain Creek
Wksht-120	WV	1,581	1,120.7	L	Fossil	x	Mt Storm
Wksht-121	OH	1,375	864.8	R (Small)	Fossil		Muskingum River
Wksht-122	KS	235	207.0		Fossil	x	Nearman Creek
Wksht-123	PA	418	281.2	R (Small)	Fossil	x	New Castle Plant
Wksht-124	CT	448	404.0	O/E/TR	Fossil		New Haven Harbor
Wksht-125	MO	1,160	956.6	R (Large)	Fossil	x	New Madrid
Wksht-126	OH	241	201.7	R (Small)	Fossil	x	Niles
Wksht-127	LA	1,804	1,498.2	R (Large)	Fossil		Nine Mile Point
Wksht-128	VA	1,835	2,714.5	L	Nuclear	x	North Anna Power Station
Wksht-129	FL	1,263	787.9	O/E/TR (Small)	Fossil		Northside Generating Station
Wksht-130	WI	1,170	1,097.0	GL	Fossil	x	Oak Creek
Wksht-131	CA	1,516	698.0	O/E/TR	Fossil	x	Ormond Beach
Wksht-132	NY	1,755	708.4	GL	Fossil	x	Oswego Harbor Power
Wksht-133	TX	2,211	1,715.3	O/E/TR	Fossil		P H Robinson
Wksht-134	WV	1,020	1,038.6	R (Large)	Fossil	x	Philip Sporn
Wksht-135	OH	95	100.2	R (Small)	Fossil	x	Picway
Wksht-136	MA	685	446.6	O/E/TR	Nuclear		Pilgrim
Wksht-137	TX	721	544.3	Reservoir	Fossil	x	Pirkey
Wksht-138	CA	1,906	462.8	O/E/TR	Fossil	x	Pittsburg Power
Wksht-139	WI	1,041	1,025.1	GL	Nuclear	x	Point Beach
Wksht-140	FL	1,621	1,253.9	O/E/TR	Fossil	x	Port Everglades
Wksht-141	PA	570	314.1	R (Small)	Fossil	x	Portland
Wksht-142	VA	1,849	227.3	O/E/TR (Small)	Fossil		Possum Point
Wksht-143	CA	362	201.7	O/E/TR	Fossil	x	Potrero Power
Wksht-144	OH	525	322.5	R (Large)	Fossil		R E Burger
Wksht-145	NY	498	489.9	GL	Nuclear	x	R. E. Ginna
Wksht-146	CA	1,310	1,372.8	O/E/TR	Fossil	x	Redondo Beach LLC
Wksht-147	OH	200	172.6	R (Large)	Fossil	x	Richard Gorsuch
Wksht-148	IA	470	784.8	L	Fossil		Riverbend
Wksht-149	FL	556	564.9	O/E/TR	Fossil	x	Riviera
Wksht-150	AR	863	442.7	R (Large)	Fossil		Robert E Ritchie

Table D: Plants with Worksheets/Selected for Analysis (cont.)

No.	State	MW	Flow (MGD)	Water Type	Fuel Type	Selected for Analysis	Facility Name
Wksht-151	NC	1,775	1,096.1		Fossil		Roxboro
Wksht-152	TX	1,809	442.7	L	Fossil	x	Sabine
Wksht-153	NJ	2,342	3,355.7	O/E/TR (Small)	Nuclear	x	Salem
Wksht-154	CA	2,150	2,295.4	O/E/TR	Nuclear	x	San Onofre Nuclear Generating Station
Wksht-155	FL	2,027	166.8	R (Small)	Fossil		Sanford
Wksht-156	CA	803	496.4	O/E/TR	Fossil		Scattergood
Wksht-157	FL	98	129.6	R (Large)	Fossil		Scholz
Wksht-158	PA	199	140.9	R (Small)	Fossil		Schuylkill Generating Station
Wksht-159	NH	1,220	593.3	O/E/TR	Nuclear	x	Seabrook
Wksht-160	NJ	522	540.3	O/E/TR	Fossil		Sewaren Generating Station
Wksht-161	PA	603	452.4	R (Large)	Fossil	x	Shawville
Wksht-162	FL		260.1	M	Fossil		Smith
Wksht-163	CA	707	596.6	O/E/TR	Fossil		South Bay Power Plant
Wksht-164	TX	844	405.9	O/E/TR	Fossil	x	SR Bertron
Wksht-165	FL	1,678	1,394.8	O/E/TR	Nuclear	x	St Lucie
Wksht-166	MI	1,419	1,162.0	GL	Fossil	x	St. Clair
Wksht-167	ND	188	142.2	R (Small)	Fossil	x	Stanton
Wksht-168	IN	515	606.2	GL	Fossil		State Line Energy
Wksht-169	LA	408	158.4	R (Small)	Fossil		Sterlington
Wksht-170	VA	1,598	2,417.2	O/E/TR (Small)	Nuclear		Surry Power Station
Wksht-171	FL	307	173.2	R (Small)	Fossil	x	Suwanee
Wksht-172	MN	110	141.5	L	Fossil	x	Syl Laskin Energy Center
Wksht-173	MN	200	290.2	GL	Fossil	x	Taconite Harbor Energy Center
Wksht-174	IN	995	1,065.8	R (Large)	Fossil	x	Tanners Creek
Wksht-175	MO	1,120	857.7	L	Fossil		Thomas Hill
Wksht-176	KY	129	180.3	R (Small)	Fossil	x	Tyrone
Wksht-177	SC	477	188.1	R (Small)	Fossil	x	Uruquhart
Wksht-178	SC	953	769.1	L	Nuclear		V C Summer
Wksht-179	OH	2,233	1,803.2	R (Large)	Fossil	x	W H Sammis
Wksht-180	SC	460	319.3	R (Small)	Fossil		W S Lee
Wksht-181	TX		2,001.6		Fossil	x	W.A. Parish
Wksht-182	HI	457	515.8	O/E/TR	Fossil		Waiau
Wksht-183	OH	1,304	739.4	R (Large)	Fossil	x	Walter C Beckjord
Wksht-184	LA	822	617.9	R (Large)	Fossil	x	Waterford 1 & 2
Wksht-185	IL	897	854.4	GL	Fossil	x	Waukegan
Wksht-186	TX	1,584	1,218.2		Fossil	x	Welsch
Wksht-187	TX	888	538.6		Fossil	x	Wilkes
Wksht-188	IL	1,060	1,292.6	M	Fossil	x	Will County
Wksht-189	SC	655	533.9	M	Fossil	x	Williams
Wksht-190	LA	2,045	1,292.6	R (Large)	Fossil		Willow Glen
Wksht-191	ME	824	494.4	O/E/TR	Fossil	x	Wyman
Wksht-192	GA	550	662.0	R (Small)	Fossil	x	Yates
Wksht-193	VA	1,141	1,445.2	O/E/TR	Fossil		Yorktown

Table D: Plants with Worksheets/Selected for Analysis (cont.)

APPENDIX E

Individual Plant Write-ups

Consumers Energy Environmental Strategies Group
Major Project Cost Estimation Workbook - Estimate Summary

Plant:	D.E. KARN 1 & 2
Location:	
Project Name:	Cooling Towers
Project #:	
Estimator:	H. Breining
Estimate Rev:	
Estimate Rev Date:	

Unit Net MW Rating:	[illegible]	Project Start Year:	[illegible]	Fuel Type:	[illegible]	Estimate Accuracy:	[illegible]
Boiler Type:		Equipment Operation Year:	[illegible]	$ Year of Estimates:	[illegible]	AFUDC Rate:	[illegible]

	Major Equipment	%	Material	%	Labor	%	Manhours	%	Other	%	Project Total	%
Demolition & Sitework	$0	0.0%	$8,254,737	7.1%	$81,667	0.1%	1,063	9.9%	$0	0.0%	$8,336,404	7.2%
Foundations & Concrete	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Structural & Architectural	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Piping, Valves, & Accessories	$0	0.0%	$30,724,737	26.5%	$326,670	0.3%	4,250	39.6%	$5,684,075	4.9%	$36,735,481	31.6%
Insulation & Lagging	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Mechanical Equipment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Electrical Equipment	$0	0.0%	$11,659,750	10.0%	$408,219	0.4%	5,433	50.6%	$543,947	0.5%	$12,611,916	10.9%
Electrical Commodities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Electrical High Voltage & Substation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Controls & Instrumentation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Subtotal Direct Costs	$0	0.0%	$50,639,224	43.6%	$816,556	0.7%	10,746	100.0%	$6,228,022	5.4%	$57,683,802	49.7%
Sales Tax												
Total Direct Costs	$0	0.0%	$50,639,224	43.6%	$816,556	0.7%	10,746	100.0%	$6,228,022	5.4%	$57,683,802	49.7%
Construction Indirects & Services												
- Field Office Expense	$0	0.0%	$32,000	0.0%	$0	0.0%	0	0.0%	$100,000	0.1%	$132,000	0.1%
- Construction Equipment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,000,000	1.7%	$2,000,000	1.7%
- Small Tools	$0	0.0%	$1,263	0.0%	$0	0.0%	0	0.0%	$205,000	0.2%	$206,263	0.2%
- Consumable Materials and Safety Supplies	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$24,497	0.0%	$24,497	0.0%
- Temporary Facilities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$180,000	0.2%	$180,000	0.2%
- Temporary Utilities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$30,000	0.0%	$30,000	0.0%
- Construction Permits	$0	0.0%	$100,000	0.1%	$0	0.0%	0	0.0%	$18,000	0.0%	$118,000	0.1%
- Site Services & Scaffolding	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$1,500,000	1.3%	$1,500,000	1.3%
- Site Safety and Risk Mitigation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$500,000	0.4%	$500,000	0.4%
- Construction Testing	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$60,000	0.1%	$60,000	0.1%
- Performance Testing	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$450,000	0.4%	$450,000	0.4%
- Preop Testing / Start-up	$0	0.0%	$195,721	0.2%	$0	0.0%	0	0.0%	$865,257	0.7%	$1,060,978	0.9%
Subtotal Construction Indirects and Services	$0	0.0%	$328,984	0.3%	$0	0.0%	0	0.0%	$5,932,754	5.1%	$6,261,738	5.4%
Project Indirects												
- MP&C Project Management	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$4,614,704	4.0%	$4,614,704	4.0%
- Owners Engineer	$0	0.0%	$804,599	0.7%	$0	0.0%	0	0.0%	$1,153,676	1.0%	$1,958,275	1.7%
- Construction Management	$0	0.0%	$3,061,589	2.6%	$0	0.0%	0	0.0%	$1,153,676	1.0%	$4,215,265	3.6%
- Engineering	$0	0.0%	$4,765,482	4.1%	$0	0.0%	0	0.0%	$2,307,352	2.0%	$7,072,834	6.1%
- Warranty Reserve	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Commodity Price Adjustment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Project Contingency	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$28,841,901	24.8%	$28,841,901	24.8%
- Liability Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Builders Risk Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Special Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- ESD Support	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,307,352	2.0%	$2,307,352	2.0%
- Lab Services	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Abatement	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Inventory Reduction	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- E&S	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,307,352	2.0%	$2,307,352	2.0%
- A&G	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$865,257	0.7%	$865,257	0.7%
Subtotal Project Indirects	$0	$0	$8,631,670	$0	$0	$0	$0	$0	$43,551,270	$0	$52,182,940	$0
Project Total	**$0**	**0.0%**	**$59,599,877**	**51.3%**	**$816,556**	**0.7%**	**10,746**		**$55,712,046**	**48.0%**	**$116,128,479**	
$/kW	$0		$116		$2				$108		$225	

Consumers Energy Numbers / Pollution Control Model Inputs

Project Total		Cost of Removal (COR)		Net Plant (Project Total - COR)		AFUDC		
$	$/kW	$	$/kW	$	$/kW	Will AFUDC Apply to Project?	$	$/kW
$116,128,479	$225	$8,336,404	$16	$107,792,075	$209	yes	$17,145,407	$33

Notes:

Project cost estimates as provided by J. Gulvas were entered into the following sheets with the following EXCEPTIONS:
1. There is an additional $1.1M in the cash flow that John included for testing required by the imposed rule.
2. ESD/MPC costs that John provided totaled $617,400. The cost estimate sheets estimated about $1M in ESD/MPC costs.
3. The indirect costs above highlighted in yellow were not accounted for in the cost estimate provided by J. Gulvas.
4. The contingency was increased to 50% (was previously 25%)
5. E&S and A&G were automatically calculated by the cost estimate sheet and resulted in slightly different numbers than provide by J. Gulvas.

Consumers Energy

Consumers Energy Environmental Strategies Group
Major Project Cost Estimation Workbook - Estimate Summary

Plant: J.H. CAMPBELL 1 & 2
Location:
Project Name: Cooling Towers
Project #:
Estimator: H Brening
Estimate Rev:
Estimate Rev Date:

Unit Net MW Rating:	[illegible]	Project Start Year:	2012	Fuel Type:	COAL	Estimate Accuracy:	[illegible]
Boiler Type:		Equipment Operation Year:	2016	$ Year of Estimates:	[illegible]	AFUDC Rate:	[illegible]

	Major Equipment	%	Material	%	Labor	%	Manhours	%	Other	%	Project Total	%
Demolition & Sitework	$0	0.0%	$10,180,842	7.2%	$81,667	0.1%	1,063	9.9%	$0	0.0%	$10,262,509	7.2%
Foundations & Concrete	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Structural & Architectural	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Piping, Valves, & Accessories	$0	0.0%	$37,893,842	26.7%	$326,670	0.2%	4,250	39.6%	$7,010,359	4.9%	$45,230,870	31.9%
Insulation & Lagging	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Mechanical Equipment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Electrical Equipment	$0	0.0%	$14,380,358	10.2%	$408,219	0.3%	5,433	50.6%	$670,868	0.5%	$15,459,445	10.9%
Electrical Commodities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Electrical High Voltage & Substation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Controls & Instrumentation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Subtotal Direct Costs	$0	0.0%	$62,455,042	44.1%	$816,556	0.6%	10,746	100.0%	$7,681,227	5.4%	$70,952,825	50.1%
Sales Tax												
Total Direct Costs	$0	0.0%	$62,455,042	44.1%	$816,556	0.6%	10,746	100.0%	$7,681,227	5.4%	$70,952,825	50.1%
Construction Indirects & Services												
- Field Office Expense	$0	0.0%	$32,000	0.0%	$0	0.0%	0	0.0%	$100,000	0.1%	$132,000	0.1%
- Construction Equipment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,000,000	1.4%	$2,000,000	1.4%
- Small Tools	$0	0.0%	$1,557	0.0%	$0	0.0%	0	0.0%	$205,000	0.1%	$206,557	0.1%
- Consumable Materials and Safety Supplies	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$24,497	0.0%	$24,497	0.0%
- Temporary Facilities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$180,000	0.1%	$180,000	0.1%
- Temporary Utilities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$30,000	0.0%	$30,000	0.0%
- Construction Permits	$0	0.0%	$100,000	0.1%	$0	0.0%	0	0.0%	$18,000	0.0%	$118,000	0.1%
- Site Services & Scaffolding	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$1,500,000	1.1%	$1,500,000	1.1%
- Site Safety and Risk Mitigation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$500,000	0.4%	$500,000	0.4%
- Construction Testing	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$60,000	0.0%	$60,000	0.0%
- Performance Testing	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$450,000	0.3%	$450,000	0.3%
- Preop Testing / Start-up	$0	0.0%	$241,390	0.2%	$0	0.0%	0	0.0%	$1,064,292	0.8%	$1,305,682	0.9%
Subtotal Construction Indirects and Services	$0	0.0%	$374,947	0.3%	$0	0.0%	0	0.0%	$6,131,789	4.3%	$6,506,736	4.6%
Project Indirects												
- MP&C Project Management	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$5,676,226	4.0%	$5,676,226	4.0%
- Owners Engineer	$0	0.0%	$992,339	0.7%	$0	0.0%	0	0.0%	$1,419,057	1.0%	$2,411,395	1.7%
- Construction Management	$0	0.0%	$3,775,960	2.7%	$0	0.0%	0	0.0%	$1,419,057	1.0%	$5,195,017	3.7%
- Engineering	$0	0.0%	$5,877,427	4.1%	$0	0.0%	0	0.0%	$2,838,113	2.0%	$8,715,540	6.2%
- Warranty Reserve	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Commodity Price Adjustment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Project Contingency	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$35,476,413	25.0%	$35,476,413	25.0%
- Liability Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Builders Risk Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Special Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- ESD Support	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,838,113	2.0%	$2,838,113	2.0%
- Lab Services	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Abatement	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Inventory Reduction	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- E&S	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,838,113	2.0%	$2,838,113	2.0%
- A&G	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$1,064,292	0.8%	$1,064,292	0.8%
Subtotal Project Indirects	$0	$0	$10,645,726	$0	$0	$0	$0	$0	$53,569,383	$0	$64,215,109	$0
Project Total	$0	0.0%	$73,475,715	51.9%	$816,556	0.6%	10,746		$67,382,399	47.6%	$141,674,670	
$/kW	$0		$119		$1				$110		$230	

Consumers Energy Numbers / Pollution Control Model Inputs

Project Total		Cost of Removal (COR)		Net Plant (Project Total - COR)		AFUDC		
$	$/kW	$	$/kW	$	$/kW	Will AFUDC Apply to Project?	$	$/kW
$141,674,670	$230	$10,262,509	$17	$131,412,161	$214	yes	$20,902,418	$34

Notes:

Project cost estimates as provided by J. Gulvas were entered into the following sheets with the following EXCEPTIONS:
1. There is an additional $1.1M in the cash flow that John included for testing required by the imposed rule.
2. ESD/MPC costs that John provided totaled $617,400. The cost estimate sheets estimated about $1M in ESD/MPC costs.
3. The indirect costs above highlighted in yellow were not accounted for in the cost estimate provided by J. Gulvas.
4. The contingency was increased to 50% (was previously 25%)
5. E&S and A&G were automatically calculated by the cost estimate sheet and resulted in slightly different numbers than provide by J. Gulvas.

Consumers Energy Environmental Strategies Group
Major Project Cost Estimation Workbook - Estimate Summary

Plant:	J.H. CAMPBELL 3
Location:	
Project Name:	Cooling Towers
Project #:	
Estimator:	H. Breining
Estimate Rev:	
Estimate Rev Date:	

Unit Net MW Rating:	[illegible]	Project Start Year:	[illegible]	Fuel Type:	[illegible]	Estimate Accuracy:	[illegible]
Boiler Type:		Equipment Operation Year:	[illegible]	$ Year of Estimates:	[illegible]	AFUDC Rate:	[illegible]

	Major Equipment	%	Material	%	Labor	%	Manhours	%	Other	%	Project Total	%
Demolition & Sitework	$0	0.0%	$29,397,879	9.6%	$81,667	0.0%	1,063	9.9%	$0	0.0%	$29,479,546	9.6%
Foundations & Concrete	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Structural & Architectural	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Piping, Valves, & Accessories	$0	0.0%	$116,032,955	37.9%	$326,670	0.1%	4,250	39.6%	$7,957,705	2.6%	$124,317,329	40.6%
Insulation & Lagging	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Mechanical Equipment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Electrical Equipment	$0	0.0%	$10,140,065	3.3%	$408,219	0.1%	5,433	50.6%	$715,907	0.2%	$11,264,191	3.7%
Electrical Commodities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Electrical High Voltage & Substation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Controls & Instrumentation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
Subtotal Direct Costs	$0	0.0%	$155,570,899	50.8%	$816,556	0.3%	10,746	100.0%	$8,673,611	2.8%	$165,061,066	53.9%
Sales Tax												
Total Direct Costs	$0	0.0%	$155,570,899	50.8%	$816,556	0.3%	10,746	100.0%	$8,673,611	2.8%	$165,061,066	53.9%
Construction Indirects & Services												
- Field Office Expense	$0	0.0%	$32,000	0.0%	$0	0.0%	0	0.0%	$100,000	0.0%	$132,000	0.0%
- Construction Equipment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,000,000	0.7%	$2,000,000	0.7%
- Small Tools	$0	0.0%	$1,768	0.0%	$0	0.0%	0	0.0%	$205,000	0.1%	$206,768	0.1%
- Consumable Materials and Safety Supplies	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$24,497	0.0%	$24,497	0.0%
- Temporary Facilities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$180,000	0.1%	$180,000	0.1%
- Temporary Utilities	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$30,000	0.0%	$30,000	0.0%
- Construction Permits	$0	0.0%	$100,000	0.0%	$0	0.0%	0	0.0%	$18,000	0.0%	$118,000	0.0%
- Site Services & Scaffolding	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$1,500,000	0.5%	$1,500,000	0.5%
- Site Safety and Risk Mitigation	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$500,000	0.2%	$500,000	0.2%
- Construction Testing	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$60,000	0.0%	$60,000	0.0%
- Performance Testing	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$450,000	0.1%	$450,000	0.1%
- Preop Testing / Start-up	$0	0.0%	$274,010	0.1%	$0	0.0%	0	0.0%	$2,475,916	0.8%	$2,749,926	0.9%
Subtotal Construction Indirects and Services	$0	0.0%	$407,778	0.1%	$0	0.0%	0	0.0%	$7,543,413	2.5%	$7,951,190	2.6%
Project Indirects												
- MP&C Project Management	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$13,204,885	4.3%	$13,204,885	4.3%
- Owners Engineer	$0	0.0%	$804,599	0.3%	$0	0.0%	0	0.0%	$3,301,221	1.1%	$4,105,820	1.3%
- Construction Management	$0	0.0%	$3,061,589	1.0%	$0	0.0%	0	0.0%	$3,301,221	1.1%	$6,362,811	2.1%
- Engineering	$0	0.0%	$4,765,482	1.6%	$0	0.0%	0	0.0%	$6,602,443	2.2%	$11,367,924	3.7%
- Warranty Reserve	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Commodity Price Adjustment	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Project Contingency	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$82,530,533	26.9%	$82,530,533	26.9%
- Liability Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Builders Risk Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Special Insurance	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- ESD Support	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$6,602,443	2.2%	$6,602,443	2.2%
- Lab Services	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Abatement	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- Inventory Reduction	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$0	0.0%	$0	0.0%
- E&S	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$6,602,443	2.2%	$6,602,443	2.2%
- A&G	$0	0.0%	$0	0.0%	$0	0.0%	0	0.0%	$2,475,916	0.8%	$2,475,916	0.8%
Subtotal Project Indirects	$0	$0	$8,631,670	$0	$0	$0	$0	$0	$124,621,105	$0	$133,252,774	$0
Project Total	$0	0.0%	$164,610,346	53.7%	$816,556	0.3%	10,746		$140,838,129	46.0%	$306,265,031	
$/kW	$0		$197		$1				$169		$367	

Consumers Energy Numbers / Pollution Control Model Inputs

Project Total		Cost of Removal (COR)		Net Plant (Project Total - COR)		AFUDC		
$	$/kW	$	$/kW	$	$/kW	Will AFUDC Apply to Project?	$	$/kW
$306,265,031	$367	$29,479,546	$35	$276,785,485	$331	yes	$44,025,499	$53

Notes:

Project cost estimates as provided by J. Gulvas were entered into the following sheets with the following EXCEPTIONS:

1. There is an additional $1.1M in the cash flow that John included for testing required by the imposed rule
2. ESD/MPC costs that John provided totaled $617,400. The cost estimate sheets estimated about $1M in ESD/MPC costs.
3. The indirect costs above highlighted in yellow were not accounted for in the cost estimate provided by J. Gulvas
4. The contingency was increased to 50% (was previously 25%)
5. E&S and A&G were automatically calculated by the cost estimate sheet and resulted in slightly different numbers than provide by J. Gulvas

SWAG
Order of Magnitude
Conceptual
Preliminary
Definitive

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and other relief.	Case N°. U-17087 ALJ Mark E. Cummins

ELECTRONIC SERVICE LIST

On the date below, an electronic copy of **Direct Testimony of J. Richard Hornby on Behalf of the Michigan Environmental Council and the Natural Resources Defense Council** and **Exhibits MEC-5 through MEC-23** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

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