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The Price of Electricity from Private Power Producers

Stage II: Expansion of Sample and Preliminary Statistical Analysis

G. A. Comnes, T. N. Belden, and E. P. Kahn

Energy & Environment Division
Lawrence Berkeley Laboratory
University of California
Berkeley, California 94720

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Abstract

The market for long-term bulk power is becoming increasingly competitive and mature. Given that many privately developed power projects have been or are being developed in the U.S., it is possible to begin to evaluate the performance of the market by analyzing its revealed prices. Using a consistent method, this paper presents levelized contract prices for a sample of privately developed U.S. generation facilities. The sample includes 26 projects with a total capacity of 6,354 MW. Contracts are described in terms of their choice of technology, choice of fuel, treatment of fuel price risk, geographic location, dispatchability, expected dispatch niche, and size. The contract price analysis shows that gas technologies clearly stand out as the most attractive. At an 80% capacity factor, coal projects have an average 20-year levelized price of $0.092/kWh, whereas natural gas combined cycle and/or cogeneration projects have an average price of $0.069/kWh. Within each technology type subsample, however, there is considerable variation. Prices for natural gas combustion turbines and one wind project are also presented. A preliminary statistical analysis is conducted to understand the relationship between price and four categories of explanatory factors including product heterogeneity, geographic heterogeneity, economic and technological change, and other buyer attributes (including avoided costs). Because of residual price variation, we are unable to accept the hypothesis that electricity is a homogeneous product. Instead, the analysis indicates that buyer value still plays an important role in the determination of price for competitively-acquired electricity.

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Acronyms and Abbreviations

BPA	Bonneville Power Administration
CF or cf	Capacity Factor
Con Edison	Consolidated Edison Company of New York
CPI	Consumer Price Index
EEI	Edison Electric Institute
EIA	Energy Information Administration - U.S. Dept. of Energy
EPAct	1992 U.S. Energy Policy Act
EWG	Exempt Wholesale Generator
FERC	Federal Energy Regulatory Commission
FPA	U.S. Federal Power Act
FPC	Florida Power Corporation
GDC	Gross Dependable Capacity
GMC	Gross Maximum Capacity
GNP	Gross National Product
GNP-PI	GNP Price Index
GW	Gigawatt
IPP	Independent power producer
IOU	Investor-owned utility
JCP&L	Jersey Central Power & Light
LILCO	Long Island Lighting Company
MEC	Marginal energy cost
MMBtu	Millions of British Thermal Units
MW	Megawatt
NEP	New England Power Company
NERC	North American Electric Reliability Council
NPV	Net present value
NMPC	Niagara Mohawk Power Company
NYPSC	New York Public Service Commission
O&M	Operation and maintenance
O&R	Orange & Rockland
OFFER	U.K.'s Office of Electricity Regulation
PPA	Purchased power agreement
PPI	Producer Price Index
PUC	Public Utility Commission
PUHCA	U.S. Public Utilities Holding Company Act
PURPA	U.S. Public Utilities Regulatory Policies Act
QF	Qualifying facility
REC	Regional Electricity Company

RECC	Real economic carrying charge
RFP	Request for Proposals
RPI	Retail Price Index
UK	United Kingdom

Executive Summary

State and federal policy for the last 15 years has explicitly encouraged the development of a competitive bulk power market. Contracts executed as a result of competitive bidding or other competitive processes have now been in existence since the late 1980s and operating projects resulting from these contracts have been producing power since approximately 1990. Most analysis of competition in bulk power markets has focused on industry structure and conduct; i.e., is the underlying technology amenable to competition, do the applicable laws and regulations promote competition, and do players in the industry behave by the rules? In addition, it is possible to begin examining the degree of competition in the market by analyzing the now-available contract prices.

Twenty-Six Contracts for Private Power

Building on work that Lawrence Berkeley Laboratory (LBL) began in 1992 (Kahn et al. 1993), we set out to collect all publicly-available, competitively-procured contracts for private power. Our sample of 26 projects (Table ES-1) excludes projects priced at administratively-determined avoided costs (which still represent the majority of nonutility power developed in the U.S. to date). The total capacity of facilities included in the sample is 6,354 MW. Of that total, 4,198 MW have been constructed as of November 1994. Based on data from the Edison Electric Institute, it appears that our sample represents about 14% of the total market for nonutility power that came on line from 1990 to 1993. We believe, however, that we have acquired a considerably higher proportion of the U.S. market for *competitively acquired* nonutility generation.

Table ES-1 shows that our sample includes the following project types: three coal steam, twenty gas-fired cogeneration and/or combined-cycle, two gas-fired combustion turbine, and one wind turbine. In addition to each projects name, we identify projects with identification (I.D.) codes. Except for the wind project, all contracts executed since mid-1990 have been gas-fired. Contracts come from 11 states, but 21 of the 26 contracts come from just five: New York (6), Virginia (6), New Jersey (4), Massachusetts (3), and Florida (2). Project capacities vary by 1 gigawatt--from 40 to 1,040 MW.

Approach

We analyzed the contracts in a consistent manner. For each project, we estimate price in each year based on the purchased power agreement (PPA) (contract) and by making estimates of any other data that are required, such as fuel prices. Forecasted annual nominal prices are levelized using a 9.8%/year discount rate. We assume future inflation rates will average 4.1%/year. Prices for projects with different start dates are adjusted to put them in terms of 1994 dollars. Levelized prices provide a consistent way to measure the life cycle costs of different projects.

Table ES-1. Summary of Contract Data

Project Name	Project I.D.	Developer/Seller	Buyer	Contract Capacity (MW)	Facility Size (MW)	Term (Years)	State	Contract Executed	Commercial Operation *	Dispatch
Crown Vista	C01	Mission Energy and Fluor Daniel	Jersey Central P&L	100	300	20	NJ	Apr-90	n.k.	Full
Indiantown Cogen	C02	U.S. Generation	Florida Power	300	300	30	FL	May-90	Dec-95	Full
Chambers	C03	U.S. Generation	Atlantic City Elect.	184	224	30	NJ	Sep-88	Mar-94	Partial
Brooklyn Navy Yard A	G01	Mission Energy, York Research	Con Edison	40	40	33	NY	Oct-91	n.k.	Full
Brooklyn Navy Yard B	G02	Mission Energy, York Research	Con Edison	40	40	31	NY	Oct-91	n.k.	Full
Brooklyn Navy Yard C	G03	Mission Energy, York Research	Con Edison	90	90	31	NY	Oct-91	n.k.	Full
Holtsville	G04	New York Power Authority	Long Island Lighting Co.	136	136	20	NY	Dec-91	May-94	Partial
Dartmouth	G05	Energy Management Inc.	Commonwealth Elect.	68	68	25	MA	Sep-89	May-92	Full
Pedricktown	G06	Cogen Partners of America	Atlantic City Elect.	106	106	30	NJ	Apr-88	Feb-92	Partial
Doswell	G07	Diamond Energy	Virginia Power	600	600	25	VA	Jun-87	May-92	Full
Gordonsville	G08	Mission Energy	Virginia Power	200	200	25	VA	Jan-89	Jun-94	Full
Wallkill	G09	U.S. Generation	Orange & Rockland	95	150	20	NY	Jun-90	n.k.	Partial
Linden	G10	Cogen Technologies	Con Edison	614	614	25	NJ	Apr-89	Jul-92	Partial
Independence	G17	Sithe Energy	Con Edison	740	1040	40	NY	Dec-92	Nov-94	Minimal
Panda	G19	Panda Energy	Virginia Power	165	165	25	VA	Jan-89	Dec-90	Full
SJE Cogen	G20	Enron Power Corp	Virginia Power	210	210	25	VA	Jun-87	Mar-91	Full
Hopewell Cogen	G21	CRSS Capital	Virginia Power	248	248	25	VA	Jun-87	Aug-90	Full
North Las Vegas	G22	United Cogeneration	Nevada Power	45	45	30	NV	May-92	May-94	Full
Blue Mountain Power	G23	Destec Power	Metropolitan Edison	150	150	20	PA	Jan-93	Jul-97	Full
Enron	G24	Enron Power	New England Power	83	140	20	MA	Dec-89	Jul-93	Full
Tiger Bay	G25	Destec Power	Florida Power	217	217	30	FL	Nov-88	Jan-95	Partial
Hermiston	G26	U.S. Generation	Pacificorp	409	409	30	OR	Oct-93	Jul-96	Full
Tenaska	G28	Tenaska L.P.	Bonneville Power Admin.	240	240	20	WA	Apr-94	Aug-96	Full
Commonwealth Atlantic	P02	Mission Energy, Destec Power	Virginia Power	312	312	25	VA	Jan-89	Jun-92	Full
Hartwell	P03	Destec Power, Am. Nat. Power	Ogelthorpe Power	310	310	27	GA	Jun-92	Apr-94	Full
Franklin & Somerset	W03	Kenetech	New England Power	20	20	29	MA	Jun-93	1997 (10 MW) 1999 (20 MW)	Minimal
Subtotal: Completed as of November 1994				3,801	4,198					
Subtotal: Committed				1,901	2,156					
Total: Committed or Completed				5,702	6,354					

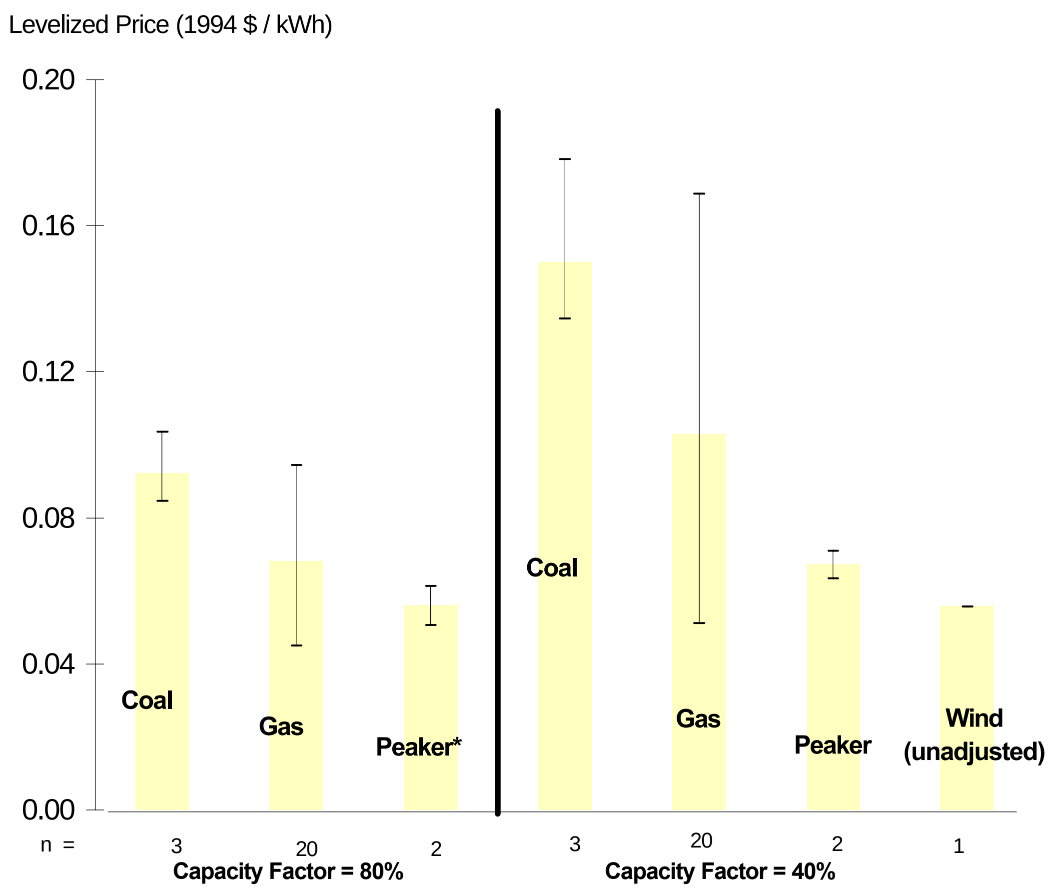
* Commercial operation dates of Dec-94 or later are estimates. n.k. = not known

Contract Prices

Our results are summarized in Figure ES-1, which shows levelized price by technology for two capacity factors: 40% and 80%. Shaded bars show the average for each technology group and the line bars indicate the range from the lowest to the highest project price in each group.

Gas-fired projects have the lowest prices on average. At an 80% capacity factor, coal projects cost an average of $0.092/kWh, which is higher than all but the most expensive of the natural gas fired projects. Our "Gas" category includes natural gas combined cycle and/or cogeneration projects. Average prices for these projects, which we call "gas nonpeakers," is $0.069/kWh at an 80% capacity factor but there is considerable variation. Two large projects, Independence and Hermiston, have levelized prices at or below $0.055/kWh. The

Figure ES-1. Levelized Price by Technology Type



Note: Shaded bars indicate group averages. Line bars indicate group max/min values.
* See Sections 3.2.1 and 3.2.4 for a discussion of the anomalous peaker prices.

economic attractiveness of gas fired technologies is robust over a wide range of gas escalation rates. The levelized prices shown in Figure ES-1 assume that coal prices stay constant in real terms and that natural gas prices will grow at 1.0%/year real. Even if natural gas prices were assumed to escalate at 4%/year real, natural gas projects would be generally cheaper than the coal projects.

Our most surprising and perhaps anomalous result is the apparent superiority of the gas combustion turbine projects (gas peakers) over a wide range of capacity factors. Gas peakers, with their low capacity costs but relatively higher heat rates, traditionally fill a niche at low annual capacity factors. Our analysis shows the peakers are the cheapest gas-fired resources at a 40% capacity factor, which is beyond their traditional role, and that they are even competitive with gas nonpeaker projects at an 80% capacity factor. Several reasons may contribute to this apparent anomaly. The two peaker projects, Commonwealth Atlantic (P02) and Hartwell (P03), are both in the Southeastern U.S., and comparable gas *non*peaker projects from that region are also low in price. Further, at least one of the peakers, Hartwell, relies on an interruptible gas supply because it is expected to operate primarily in the summer. Thus, its availability is not the same as the gas nonpeakers in the sample which tend to acquire firm, year-round gas supplies and transportation capacity. Nonetheless, given that the market for gas combustion turbines has become highly competitive and the current attractiveness of gas prices, gas combustion turbines appear to fill a wider dispatch niche than they have in the past.

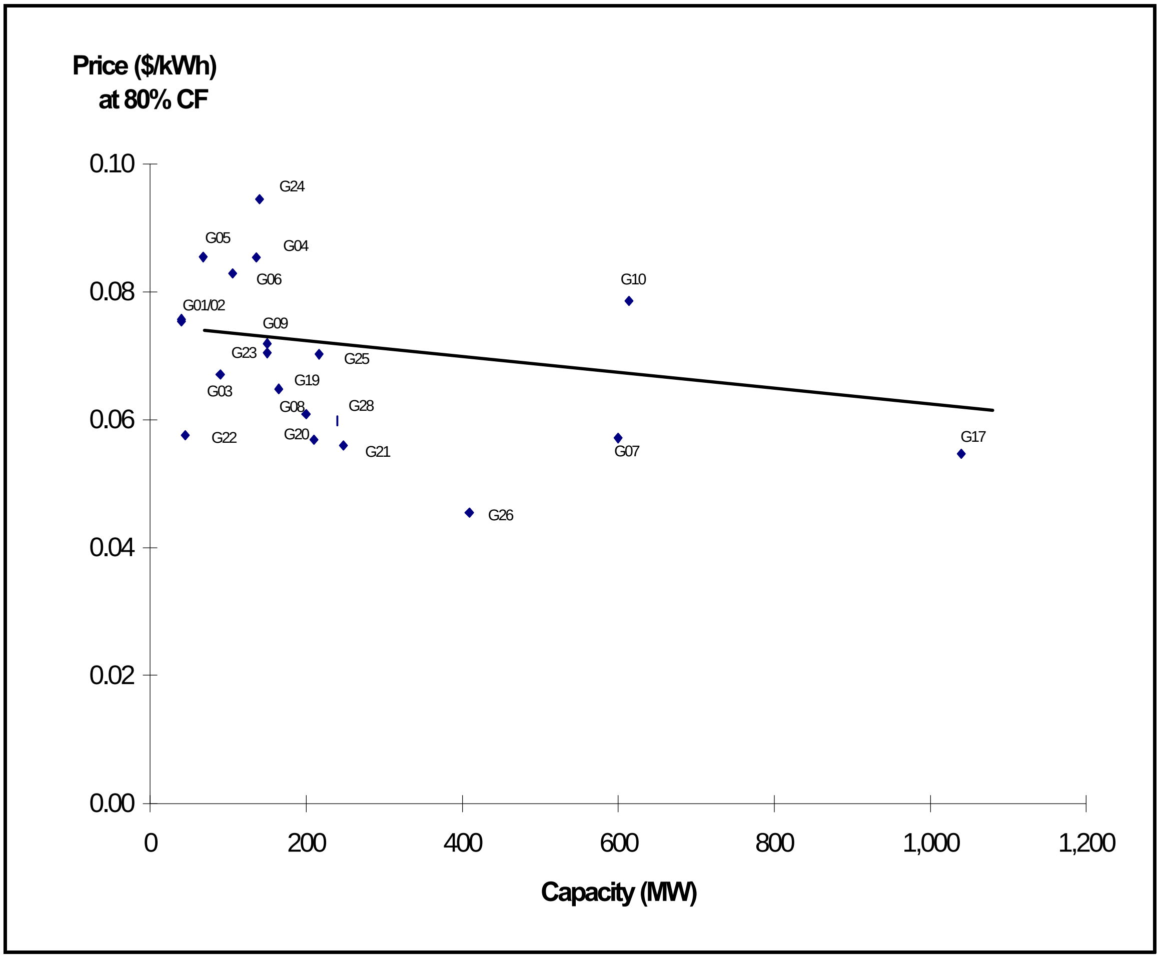
The one wind contract in the sample has a levelized price of $0.056/kWh, which looks very attractive at first glance (see Figure ES-1). A proper comparison between wind and conventional thermal projects requires adjustments for the intermittency of wind power. We make such adjustments and compute an illustrative price between $0.072/kWh and $0.104/kWh with a central price of $0.088/kWh. On this basis, wind prices are still competitive with the thermal projects in the sample.

Our projects span a wide range of capacities. We considered whether size had an impact on price. Figure ES-2 suggests that economies of scale exist, although the relationship depends heavily on several larger (> 400 MW) projects like Independence (G17), Hermiston (G26), and Doswell (G07). Figure ES-2 also shows the best fit regression line for the data. While it appears that more recent projects tend to offer lower prices, they are not always “large.” For example, North Las Vegas (G22) and Blue Mountain Power (G23) are recently executed contracts for projects that are on or below the price regression line with capacities below 200 MW.

Geographic effects on price are strong. Prices are generally highest in the Northeast and are lowest in the West, with Southeastern projects prices in between (Figure ES-3). Regional location affects price because the cost and value of purchase power varies by region. Construction costs are highest in the Northeast, as are utility buyer avoided costs.

There is an important trend in the treatment of fuel price risk. All of the gas nonpeaker projects signed during or after 1991 (ten out of 20 gas nonpeaker projects in the sample) have energy price terms that are *not* directly linked to natural gas prices. Instead, they are linked to fixed escalators, inflation indices, or buyer avoided costs. These practices address one of the biggest concerns of gas-fired electric generation, namely, its risk with respect to future fuel prices. While it is possible that a dramatic change in natural gas prices will lead to contract abrogations and renegotiations, sellers have contractually taken on significant fuel price risk.

Figure ES-2. Levelized Price versus Facility Size

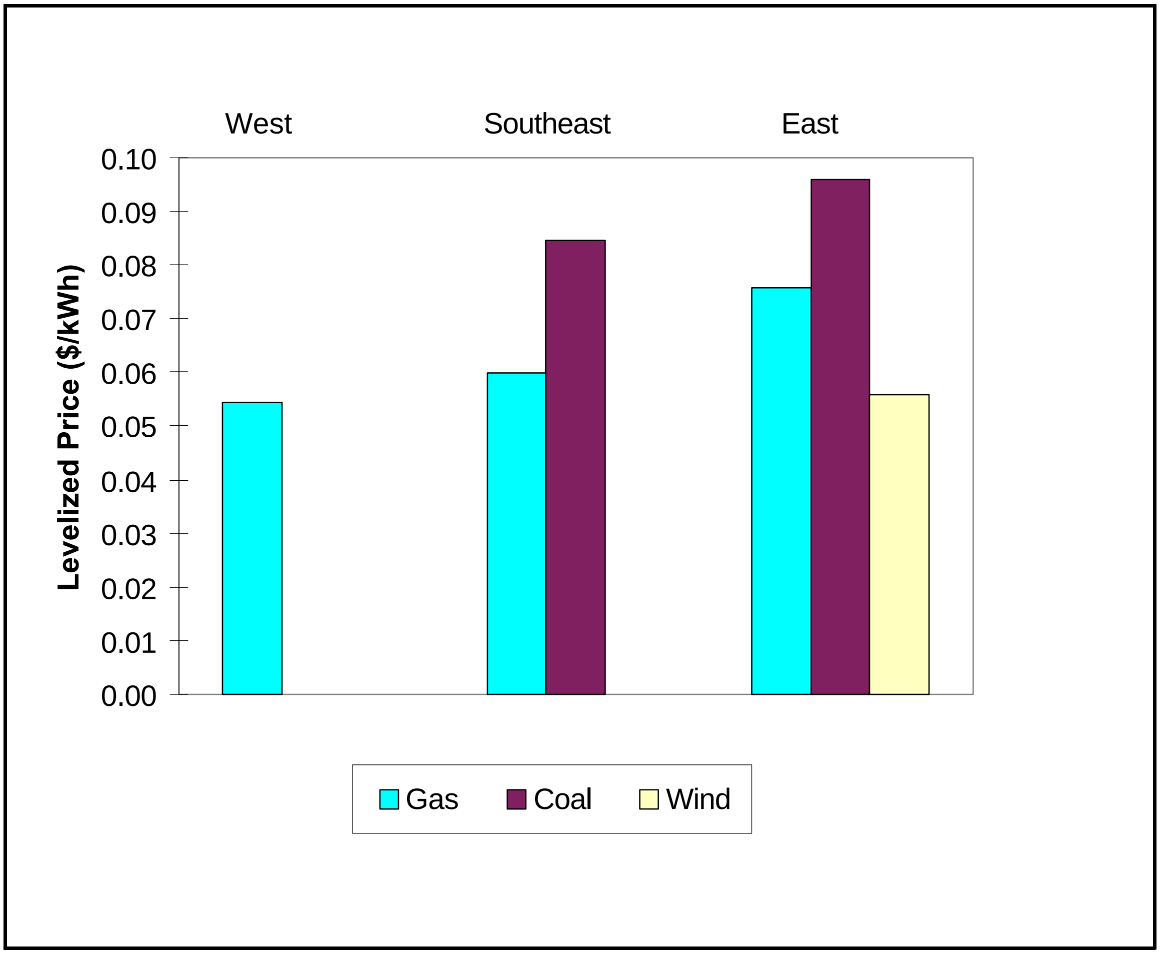


Preliminary Statistical Analysis

We conducted a preliminary statistical analysis using correlation and regression analysis. We hypothesize that four kinds of exogenous factors influence price: product heterogeneity, geographic heterogeneity, technological and economic change, and other buyer attributes including avoided costs or willingness to pay. We constructed approximately fifteen data series to measure these factors. For 23 coal and gas nonpeaker projects, we found that a constant, a Northeast integer (dummy) variable, a coal technology dummy variable, coal prices delivered to the buyer, contract term, and facility size explain 88% of all price variation. All of the variables have their expected signs. The regression equation indicates that a coal project adds $0.014/kWh to a project price and a project located in the Northeast adds $0.013/kWh to the price. We find the significance of the coal prices interesting and we believe that they may be a reasonable proxy for utility buyer avoided costs.

Discussion of Major Findings

Figure ES-3. Levelized Price by Technology and Region



Prices for nonutility power exhibit considerable variability. Even after adjusting for project-related costs and regional location, this variability persists. Thus, there is still no "one" price for electricity, at least not in the long-term contracts market. Buyers will still need to conduct considerable research on recent contract prices to see if proposed bids are reasonable relative to recent experience in the marketplace. Similarly, policy makers will have a hard time measuring the benefits of a competitive industry structure by observing prices. Instead, they will have to remain satisfied with policies and regulations regarding industry structure and conduct, such as keeping barriers to entry low and competitive acquisition processes fair.

Some analysts have predicted that electricity will become more commodity-like in the future. If it does, price variation among contract prices should decrease. Continuing to measure prices and other contract terms will help policy makers evaluate this potential trend towards commoditization.

A Final Recommendation Regarding Contract Confidentiality

We encountered considerable difficulties when collecting contracts for our analysis. We believe that state PUCs and the FERC should keep contracts publicly available. There were at least ten projects which qualified for our sample but were excluded because the contracts were confidential. Existing policies in many states either explicitly or implicitly allow for contract confidentiality. The FERC generally requires contracts to be made public, but is only beginning to require consistent reporting of transactions made under market-based pricing. More troublesome, we believe the explicit or implicit disclosure policies of many states impedes the development of a competitive bulk power market. Public prices improve both the value of bids made by developers and the decisions made by utility buyers and regulatory commissions. If a decision maker is concerned that contract disclosure will disrupt the competitive acquisition process, we suggest that confidentiality be allowed for a limited time after which disclosure of contracts for winning projects be made.

Introduction

1.1 The Emerging Competitive Market for Private Power

There is considerable evidence that the market for bulk power is becoming increasingly competitive. At a minimum, there is general acceptance by industry participants that it is no longer a natural monopoly.[1] The Public Utilities Regulatory Policies Act (PURPA) initially created a new market for nonutility power through the establishment of qualifying facilities (QFs) and through the requirement that traditional, vertically integrated utilities interconnect with and buy power from QFs at avoided cost.[2] The growth in non-utility power during the 1980s was also fueled by changes in generation technology (most notably advances in gas-fired technologies) and the improved availability and low prices for natural gas. Furthermore, investor-owned utilities became increasingly reluctant to finance new generating capacity on their balance sheets because of perceived and real threats of disallowances. The trend towards private power outgrew its QF niche as demand grew for nonutility facilities, but the shrinking pool of steam host sites precluded all gas-fired facilities from qualifying as QFs. FERC developed standards for non-QF, nonutility suppliers, first by attempting a generic rulemaking in 1988 and, second, by building a case law that allows market-based pricing of wholesale (bulk power) transactions if the bulk power provider can demonstrate a lack of market power and the absence of real or potential affiliate abuse. In parallel with the FERC, many state PUCs developed rules for competitive bidding for new power resources acquired by utilities under their jurisdiction. Resolution of the conflict between the demand for private power and the remaining legal and regulatory constraints was partially resolved with the passage of the 1992 Energy Policy Act (EPAct). EPAct allows for the creation of exempt wholesale generators (EWGs), a regulatory and legal status that allows many more companies, including equipment vendors and utilities selling outside of their service territories, to participate in power projects. These projects, like any other bulk power provider, may request market-based pricing.

With these industry events and trends, the question remains whether the market is sufficiently competitive to allow for a move to market-based pricing and away from regulation. Most of the analysis on competition has focused on evidence of market structure and conduct, such as whether there are barriers to entry and whether competitive solicitation processes promote competition. This kind of analysis establishes adequate competition by looking at such things as the ratio of MWs bid to resource need, and the rules regarding the bid process including

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1 See, for example, CPUC (1994), pp. 37.

2 QFs include certain facilities that utilize renewable energy sources and cogeneration facilities that pair fossil-fuel electricity production with a steam host.

auction design and rules for affiliated bidders. Relatively less work has been done to see whether observed prices provide evidence for competition.[3] When focusing on prices, it initially appears that certain pieces of evidence that establish competition in bulk power markets are missing. First, prices for many new nonutility projects, especially prices based on the executed purchase power agreement, are not publicly available. Second, from the limited amount of price data that is available for nonutility projects, considerable price variation exists, and that on its face violates the competitive “law of one price” (Sichel and Eckstein 1977, pp. 21).

1.2 Study Objectives

This report represents a continuation of an earlier report by Lawrence Berkeley Laboratory (LBL) that examined prices in the competitive segment of the private bulk power market (Kahn et al. 1993). In that report, LBL analyzed 11 contracts for the purchase of power from new coal- and gas-fired facilities developed by private parties. In this report, the sample has been expanded to 26 contracts. The types of facilities represented by the sample contracts now includes coal, gas-fired cogeneration and/or combined cycle, gas-fired combustion turbines, and wind generation.

The primary objectives of this Stage II report are: (1) to facilitate price revelation in the bulk power market using a standardized way of presenting prices, (2) to better understand price variations in contracts by exploring the data and using a preliminary statistical analysis, and (3) to consider policy implications of the data analysis given the emerging competitive market for bulk power.

Unlike power produced from utility sources, the price of power from nonutility sources is not readily available. Independent power producers (IPP) are not required to report their generating costs or prices to the Energy Information Administration (EIA). Utilities report purchased power costs in their FERC Form 1 reports, but this information is now only beginning to be standardized. Moreover, FERC Form 1s do not provide future costs even though most utilities make long-term commitments when they purchase from private sources. In the IPP market, some information on bid prices is usually available in the trade press, but consistently calculated levelized prices of winning projects are rarely available. We attempt to improve price revelation in the bulk power market by analyzing purchased power agreements or “contracts”, which are the best source of data on long-run prices. Our primary calculations are 20-year and contract-life-levelized prices ($/kW and $/kWh).

[3] An exception is Cameron (1992).

We provide insight into contract prices by presenting levelized costs while varying key variables that are uncertain, such as capacity factor[4] and fuel price. We compare our sample's contract prices to prices available for similar projects from the United Kingdom, a country that is also trying to foster a competitive market for generation. For renewable projects that provide intermittent supply, we present a methodology for adjusting prices and present illustrative numbers. We also provide an analysis of how these contracts manage fuel price risk.

In our statistical analysis, we consider conceptually the factors that may explain variations in price. In a simple model of a competitive market, there is only one price for each product in the economy. Differences in prices must be explained by differences in product type or geographic location. In a more sophisticated model of a market, price variation will exist if market participants are able to price discriminate. Such a market may be competitive so long as barriers to entry are not formidable. We attempt to normalize prices in the sample for variations caused by product and geographic heterogeneity. Using correlation and regression analysis, we identify which factors appear most significant.

1.3 Report Structure

This report is organized as follows. Chapter 2 presents the characteristics of the contract sample, reviews the methodology, and summarizes economic and operational assumptions. Chapter 3 presents the results of our exploratory data analysis and preliminary statistical analysis. Chapter 4 discusses the policy implications of our work, including the issue of contract confidentiality, which we found to be a crucial impediment to our analysis.

[4] *Capacity factor* is defined as the average power output of a plant over a given time period (usually a year) divided by its capacity. We examine prices at different capacity factors, because most projects are dispatchable and it is, thus, hard to predict realized capacity factors.

Project Characteristics and Methodology

2.1 Introduction

In this chapter we introduce the sample of projects and their key characteristics, including the choice of technology and or fuel, location, size, dispatchability, and term. We compare our sample to the total population of nonutility contracts completed during a similar period. We also summarize our methodology and the basic economic and operational assumptions used in our levelized price analysis.

2.2 Characteristics of Projects Included in the Sample

In order to meaningfully analyze behavior or performance in a market, we must define the market in terms of a product and a geographic area. At the broadest level, we can state our product and geographic definitions succinctly: the product is firm bulk power sold by private power producers and the geographical area is the U.S. We intentionally exclude two other types of bulk power projects or contracts: utility-owned projects and interutility contracts. Projects owned by the buyer, or where the buyer has or plans to have a large equity interest in the project, are excluded because they usually do not have a clearly defined contract or price. Interutility contracts are, in theory, more appropriate for inclusion in our sample. However, because these transactions involve a complicated range of contract types that vary in term and reliability, they have been excluded at this time.[5] In addition, prices for interutility bulk power are usually set outside of competitive solicitations. Although FERC has begun to accept inter-utility contracts with market-based pricing and competitive bidding processes that include all supply sources are becoming more popular, cost-of-service standards are still prevalent in the pricing of interutility contracts. Limiting the sample improves its homogeneity which makes our analysis findings more powerful.

In addition to requiring that the power be sold by a nonutility developer, we limited ourselves to projects that are new or repowered facilities that provide long-term firm power and situations in which the power purchase contract was awarded through some type of competitive process. Thus, our contract sample explicitly excludes QF contracts with prices determined through administrative processes or through standard contracts. The majority of nonutility contracts in the U.S. are of these type although the determination of price via competitive processes is now becoming the norm. Our primary method of

[5] In future work, we hope to include a more expansive sample of bulk power contracts that includes interutility contracts.

identifying projects involved review of the trade press, including issues of the *Independent Power Report* and *Independent Energy*.

Using our criteria, we collected and analyzed twenty-six contracts (Table 2-1). The major types of project technologies and their frequencies are: natural gas cogeneration and/or combined cycle, also known as nonpeakers (20); natural-gas fired combustion turbines, also known as peakers (2); coal-fired steam (3); and wind turbine (1). Table 2-1 also includes project identification (ID) codes: C, G, P, and W for coal, gas nonpeaker, gas peaker, and wind, respectively.

Contracts come from 11 states, but 21 of the 26 projects come from just five states: New York (6), Virginia (6), New Jersey (4), Massachusetts (3), and Florida (2). Notably absent are contracts from California, Montana, and Wisconsin. Also, we believe that the two contracts from the Pacific Northwest (i.e., the contracts from Oregon and Washington) do not adequately represent the actual activity level of competitive power procurement occurring in that region. Most projects awarded through California s recent competitive process (i.e., the BRPU) have been contested by two utilities (SCE and SDG&E) and no contracts were made available in time for inclusion into our sample.[6] The other indicated states are under represented because their state policies keep executed contracts confidential. The issue of confidentiality is discussed further in Chapter 4.

It is important to note that although we included projects that were competitively acquired, not all of them were procured as the result of formal bidding processes. Some of the bigger projects are in this category. Independence, Linden, and Tiger Bay were initially standard-offer type projects that went through sufficient renegotiations for us to deem them competitively acquired. For all projects, we have used the latest contract amendments we could acquire. Hermiston was also acquired via bilateral negotiation rather than bidding.

In terms of total capacity, the sample includes facilities that total 6,354 MW in size. Of that amount, 4,198 MW was completed as of November 1994. We do not have comparable information on the total *population* of executed, competitively acquired, private power contracts in the U.S. We do know, however, that during the period 1990 through 1993, 16,485 MW of nonutility capacity was added in the U.S., including capacity from QFs (Edison Electric Institute (EEI) 1994). During that same period, 2,386 MW of contract capacity was completed in our sample. Thus, using EEI's broad definition of nonutility generation, our sample appears to capture 14% of the population. We have almost certainly captured a higher percentage of contracts that were executed as a result of competitive solicitations.

6 Prior to the competitive solicitations by the California utilities, all previous contracts were of the standard-offer type.

Table 2-1. Summary of Contract Data

Project Name	Project I.D.	Developer/Seller	Buyer	Contract Capacity (MW)	Facility Size (MW)	Term (Years)	State	Contract Executed	Commercial Operation *	Dispatch
Crown Vista	C01	Mission Energy and Fluor Daniel	Jersey Central P&L	100	300	20	NJ	Apr-90	n.k.	Full
Indiantown Cogen	C02	U.S. Generation	Florida Power	300	300	30	FL	May-90	Dec-95	Full
Chambers	C03	U.S. Generation	Atlantic City Elect.	184	224	30	NJ	Sep-88	Mar-94	Partial
Brooklyn Navy Yard A	G01	Mission Energy, York Research	Con Edison	40	40	33	NY	Oct-91	n.k.	Full
Brooklyn Navy Yard B	G02	Mission Energy, York Research	Con Edison	40	40	31	NY	Oct-91	n.k.	Full
Brooklyn Navy Yard C	G03	Mission Energy, York Research	Con Edison	90	90	31	NY	Oct-91	n.k.	Full
Holtsville	G04	New York Power Authority	Long Island Lighting Co.	136	136	20	NY	Dec-91	May-94	Partial
Dartmouth	G05	Energy Management Inc.	Commonwealth Elect.	68	68	25	MA	Sep-89	May-92	Full
Pedricktown	G06	Cogen Partners of America	Atlantic City Elect.	106	106	30	NJ	Apr-88	Feb-92	Partial
Doswell	G07	Diamond Energy	Virginia Power	600	600	25	VA	Jun-87	May-92	Full
Gordonsville	G08	Mission Energy	Virginia Power	200	200	25	VA	Jan-89	Jun-94	Full
Wallkill	G09	U.S. Generation	Orange & Rockland	95	150	20	NY	Jun-90	n.k.	Partial
Linden	G10	Cogen Technologies	Con Edison	614	614	25	NJ	Apr-89	Jul-92	Partial
Independence	G17	Sithe Energy	Con Edison	740	1040	40	NY	Dec-92	Nov-94	Minimal
Panda	G19	Panda Energy	Virginia Power	165	165	25	VA	Jan-89	Dec-90	Full
SJE Cogen	G20	Enron Power Corp	Virginia Power	210	210	25	VA	Jun-87	Mar-91	Full
Hopewell Cogen	G21	CRSS Capital	Virginia Power	248	248	25	VA	Jun-87	Aug-90	Full
North Las Vegas	G22	United Cogeneration	Nevada Power	45	45	30	NV	May-92	May-94	Full
Blue Mountain Power	G23	Destec Power	Metropolitan Edison	150	150	20	PA	Jan-93	Jul-97	Full
Enron	G24	Enron Power	New England Power	83	140	20	MA	Dec-89	Jul-93	Full
Tiger Bay	G25	Destec Power	Florida Power	217	217	30	FL	Nov-88	Jan-95	Partial
Hermiston	G26	U.S. Generation	Pacificorp	409	409	30	OR	Oct-93	Jul-96	Full
Tenaska	G28	Tenaska L.P.	Bonneville Power Admin.	240	240	20	WA	Apr-94	Aug-96	Full
Commonwealth Atlantic	P02	Mission Energy, Destec Power	Virginia Power	312	312	25	VA	Jan-89	Jun-92	Full
Hartwell	P03	Destec Power, Am. Nat. Power	Ogelthorpe Power	310	310	27	GA	Jun-92	Apr-94	Full
Franklin & Somerset	W03	Kenetech	New England Power	20	20	29	MA	Jun-93	1997 (10 MW) 1999 (20 MW)	Minimal
Subtotal: Completed as of November 1994				3,801	4,198					
Subtotal: Committed				1,901	2,156					
Total: Committed or Completed				5,702	6,354					

* Commercial operation dates of Dec-94 or later are estimates. n.k. = not known

As would be expected for facility-based contracts, all contracts have terms of 20 years or greater. Most contracts have terms in the 20- to 30-year range, although one contract (Independence) has a 40 year term. How we address contracts of different durations is taken up further in Section 2.3.2.

2.2.1 Project Dispatchability

Traditionally, dispatchability has been defined as the ability of generation output to follow fluctuations in load (Kahn et al. 1989; Kahn et al. 1990, pp. 4-1). This feature of power projects is standard for utility-owned units, but not for PURPA QFs. The rights of QFs to sell all output to utilities meant that they were typically not dispatchable until the widespread advent of competitive bidding. *Economic* dispatchability incorporates the flexibility identified in this traditional definition but also includes the flexibility to adjust purchases to minimize buyer costs. In Kahn et al. (1990), we distinguished three distinct aspects of dispatchability: curtailment, commitment, and chronology. Contract terms that address all aspects of dispatchability are evident in our sample. Curtailment is the ability to reduce the output of a project and is usually defined in terms of hours or megawatt-hours per year.

Curtailment may allow the buyer to reduce takes in any given time period, but usually does not imply that the buyer can start or stop a unit or can control output over short time periods. The ability to start and stop a unit is defined in commitment provisions of a contract, which usually allows the buyer the flexibility to do so on a daily or weekly basis. Chronology attributes relate to the ability of the buyer to adjust purchases on an hourly or instantaneous basis. Ramp rates are a common chronological attribute. At the limit, chronological dispatchability is maximized when the buyer is afforded automatic load control of the project.

Contracts in our sample included these multiple aspects of dispatchability. We attempted to collapse these multiple definitions into a single index for ranking dispatchability. First, we defined "fully dispatchable" projects to include ones where the buyer could curtail at least 90% of the project's annual available hours or energy. Using this scoring system, 18 projects were fully dispatchable (Table 2-1). Interestingly, only five of these projects are IPPs; the rest (13) were QFs. Second, we defined a category called "minimally dispatchable" to include projects that required that the buyer take more than 90% of available power or energy in a given year. Only two projects, Independence (G17) and the Kenetech wind project (W03), were minimally dispatchable. In between these two categories, we defined projects to be "partially dispatchable." Six projects are in this category, typically because their contracts require that buyers take power from the project for a certain number of hours per year. In contrast to the original PURPA standards, which generally did not require QFs to be dispatchable, dispatchability has found its way into nearly all competitively acquired contracts. We used this ranking method in our statistical analysis.[7]

2.3 Methodology

The basic methods used in this report have not changed significantly compared to our Stage I report (Kahn et al. 1993, pp. 3-5). Levelized price as articulated in the purchase power agreement (PPA) or "contract" is still the primary metric of analysis. Although many of the contracts give sufficient information for computing prices, some of the contracts refer to information that is not readily available or is dependent upon a future event. In these cases, we collected supplemental information and estimated missing data as necessary to estimate contract prices. In addition, some of the projects are now operating, and information on recorded price is available. When it was available, we used this historical (recorded) information to either check our price estimates or to estimate data that was not adequately specified in the contracts (see Appendix A for a detailed description of each project).

[7] Because of the limited sample size, however, we created an integer variable where one value (= 1) included fully dispatchable projects and the other value (= 0) included both partially and minimally dispatchable projects.

The remainder of this chapter identifies and discusses important methodological issues and assumptions. Specifically, we examine technical issues that arise in our computation of levelized price, including real versus nominal levelization methods and the issue of end effects.

2.3.1 Economic Figure of Merit: Levelized Contract Prices

We compute a single *levelized* price that is representative of the multi-year stream of prices. First, project costs are normalized with respect to operating parameters (e.g., capacity factor) and fuel price expectations. Once costs are normalized in this way, the net present values (NPV) of the projects are computed. Projects with different start dates are adjusted for inflation to 1994 dollars.[8] Projects may then be compared to each other using prices normalized to capacity ($/kW) or energy ($/kWh). In either case, prices are shown for each project year, in nominal dollars. Then, multi-year prices are levelized. Alternative methods of levelization are available and our choice of method is discussed in Section 2.3.3.

2.3.2 Base-Case Economic and Operational Assumptions

We use similar economic assumptions that were used in our Stage I analysis (Kahn et al. 1993). These are:

Economic Assumptions

- General prices (inflation) are assumed to escalate at 4.1%/year. On a forecast basis, we use the same rate for all inflation indices used in contracts. Contracts most commonly use the Gross National Product (GNP) Implicit Price Deflator, the GNP Price Index (GNP-PI) or the Consumer Price Index (CPI). For historical years, we attempt to use actual recorded inflation rates whenever possible.

- The discount rate is set at 9.8%/year, which, given our long-term inflation forecast, is equivalent to a real discount rate of 5.5%/year.

- Oil and natural gas prices are assumed to move in parity on a forecast basis. Our base-case assumption is that natural gas wellhead prices rise at a rate of 5.1%/year, or 1%/year real. We also evaluated projects using higher and lower oil and natural gas price escalation rates (see section 3.2.7). Natural gas transportation costs, both fixed and variable, are assumed to grow in parity with inflation. Many contracts escalate *delivered* natural gas prices or electric energy prices. In these cases, we use

[8] Because most contracts specify that revenues are paid monthly, the average "time" of each year's cash flows is naturally mid-year. If significant cash flows occur at times other than year-round or at mid-year, we attempt to discount the payment as appropriate so that the dollars are mid-year dollars.

a gas *combined index*, which is a weighted average of the wellhead (weight equal to 0.67) and transport (weight equal to 0.33) indices.

- Coal prices are assumed to grow in parity with inflation.

Operational Assumptions

- Many projects have bonus and penalty provisions if projects do not operate at their expected contractual availability. We assume that all projects meet expected performance targets, so the impact of these contract provisions on price is ignored.

- We generally ignore the impact of startup payments and fuel oil inventory carrying charges. When we attempted to explicitly estimate these contract provisions, we generally found them to impact prices by less than 1%.

- We assume that projects that can run on natural gas use that fuel 100% of the time. An important exception is that some contracts base pricing on oil for some seasons of the year, regardless of the actual fuel burned. In these cases, we estimate an oil price to compute the contract price.

- Projects are assumed to start on their actual start date (for operational projects) or on the expected operations date (based on the contract or the most recent trade press information).

2.3.3 Other Methodological Issues

Accounting for End Effects

Contract duration varies considerably among our sample of projects (see Table 2-1). An important question is how to address the impact on levelized prices from projects that have longer lives than others. Differences in prices may not reflect differences in marginal value; instead, they may reflect the fact that we've ignored the true cost of replacement power that will be needed when shorter contracts expire. This problem is commonly known as the *end effects* problem. One easily identified source of bias comes from assumptions regarding the real escalation rates for fuel for projects that have significant variable cost components in their price. If real escalation rates are above zero, contracts with longer terms will be biased upward compared to shorter-term contracts, solely because more high-cost-fuel years are included in the analysis. For example, the levelized price for the Independence Project (G17) rises 8% when the time horizon changes from 20 years to 40 years (the contract term).

One way to correct for the end effects problem is to choose a fixed time frame that is greater than the longest term of any of the sample contracts. Then, for contracts with terms less than the chosen time frame, we would estimate the cost of the buying utility's next best source of electricity and incorporate this replacement resource into the levelized price calculation (Kahn et al. 1993, pp. 21). This approach is difficult to implement because it is hard to determine the type and cost of the next best resource for each utility that would be chosen 10 to 35 years in the future. An easier adjustment for end effects is to compare levelized costs of all contracts over a time frame equal to or smaller than (nearly) all contract terms in the sample. Although less ideal, this method of adjusting for end effects is a reasonable way to eliminate the bias resulting from projects' sensitivity to assumptions regarding real fuel escalation rates. We have used this method to adjust for end effects using a 20-year time frame. When contracts are longer than 20 years, we compute a 20-year levelized price and generally use this price in our statistical analysis.

Levelization Methodology: Real versus Nominal

Competing methods exist for computing levelized prices, i.e., nominal vs. real. A standard annuity formula applied to a project's NPV gives a levelized value in nominal terms; i.e., payments made at those exact, constant levels will result in the same NPV as the project's actual cash flows.[9] One may also levelize NPVs in real terms using a real economic carrying charge (RECC) (National Economic Research Associates Inc. 1977).[10] Because the RECC stays constant in real terms, annual payments or prices computed using RECC must be escalated at inflation if future-year prices are displayed, as we display them, in nominal terms.

Real or nominal levelization has no impact on project comparisons, so long as a levelization method is used consistently. For this report, we have chosen the nominal levelization method because it is the standard formula used to levelize capital costs in financial markets and in the electric power industry.

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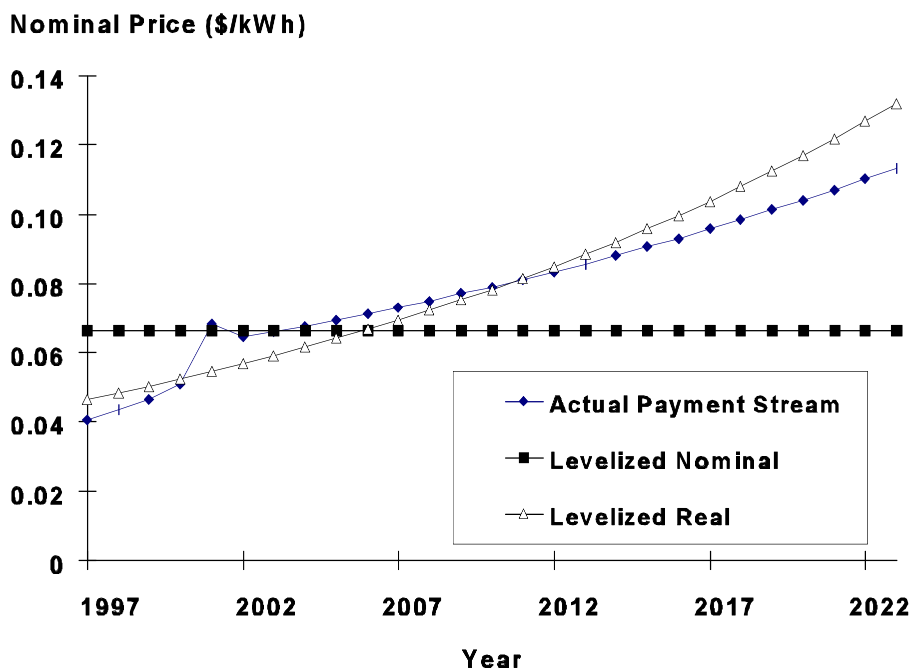
9 An annuity formula is also known as a capital recovery factor. It is equal to $\frac{r(1+r)^n}{((1+r)^n-1)}$, where r is the nominal discount rate.

10 The RECC is equal to $\frac{(r-i)(1+r)^n}{((1+r)^n-(1+i)^n)}$, where r is the nominal discount rate and i is the inflation rate.

RECC is approximately equal to a standard annuity formula in which the real discount rate $(r - i)$ is substituted for the nominal discount rate of the annuity formula.

The different characteristics of the two levelization methods are illustrated in Figure 2-1 for one of our sample contracts, Kenetech's wind contract with New England Power (NEP) (W03). The figure shows multi-year prices in three ways: as stated in the contract (first series), using nominal levelization (second series), and using a RECC levelization (third series). All three 29-year streams have the same NPV using our chosen discount rate. In the first year that the project is expected to be operational, 1997, the price is \$0.041/kWh. Using nominal levelization, the price is \$0.066/kWh.[11] Using the RECC, the price is \$0.050/kWh in the first year and rises in each year at the rate of inflation (4.1%/year). The important thing to learn from the figure is the distortion that is created if first-year-actual or RECC-levelized prices are compared to a nominal levelized price. Unfortunately, such

Figure 2-1. Illustration of Different Levelization Methods--Kenetech Wind Project



Note: Levelized price is levelized over contract life and is shown starting in1997 \$s.

[11] Levelized prices in the figure do not match levelized prices in Chapter 3 because (1) they have not been converted to 1994 \$s and (2) they are contract-life levelized rather than 20-year levelized.

apples-to-orange comparisons are common, especially in reports published in the trade press. For the Kenetech project, it appears that actual payment prices have been negotiated in a way that closely match a RECC-levelized trajectory.

Analysis of Contract Prices

3.1 Introduction

In this chapter, we present levelized prices for all of the projects and explore factors that we expect to most significantly affect price. These factors include project technology and fuel type, capacity factor, size, location, and fuel price risk. We also show the results of our method for adjusting intermittent projects for make up capacity and energy. In section 3.3, we include a conceptual discussion of relevant explanatory models and articulate specific variables, or factors, that we believe should be important in explaining price. We then conduct a preliminary statistical analysis of the data using correlation and regression analysis as our tools. Specifically, we present results of the best regression of our analysis, a six-variable model of price that indicates that prices are driven by facility size, technology type, location, local fuel prices, and contract term.

3.2 Results

We computed 20-year levelized prices for all of the projects in our sample (Table 3-1). For each project, we show its levelized capacity price, energy price, and total price at three capacity factors (20%, 40%, and 80%). The three coal projects have an average price of $0.092/kWh (simple average, 80% capacity factor) with a range of prices from $0.085 to $0.104 per kWh. The gas combined cycle and/or cogeneration (nonpeaker) projects show a much wider price range. The average price of the gas nonpeakers is $0.069/kWh, but two larger projects, Independence and Hermiston, have estimated levelized prices of only $0.055/kWh and $0.045/kWh, respectively, and the most expensive projects cost more than twice the least expensive. Surprisingly, the two gas combustion turbine (peaker) projects have very competitive prices, $0.056/kWh, even at a capacity factor of 80%. The wind project's price is $0.056 at a projected availability of 36%.

3.2.1 Contract Prices as a Function of Capacity Factor and Technology

It is useful to compare project prices at capacity factors other than 80%, as is done in Table 3-1 and in Figure 3-1. In a competitive market, we would expect different technologies with different fixed-variable pricing arrangements to provide the lowest price in a range of capacity factors that we call "dispatch niches." In general we expect high-fixed-cost projects, such as coal and gas combined cycle, to have their niche at high capacity factors and low-fixed-cost projects, such as combustion turbines, to have their niche at low capacity factors. The data, however, clearly challenge our expectations. In Figure 3-1, levelized prices are s h o w n f o r

Table 3-1. Comparison of Project Prices by Technology Type and Capacity Factor

			20-Year Levelized Prices				
			Capacity	Energy*		Total	
Fuel Type	Project ID	Project Name	$/kW-yr	$/kWh	20% cf $/kWh	40% cf $/kWh	80% cf $/kWh
Coal	C02	Indiantown Cogen	351	0.035	0.235	0.135	0.085
	C03	Chambers (Carneys Point)	324	0.042	0.230	0.137	0.088
	C01	Crown Vista	523	0.029	0.328	0.178	0.104
		Average	400	0.035	0.264	0.150	0.092
Gas	G26	Hermiston	181	0.020	0.123	0.071	0.045
	G17	Independence	43	0.049	0.073	0.061	0.055
	G21	Hopewell Cogen	150	0.035	0.120	0.077	0.056
	G20	Richmond Power Ent./SJE Cogen	145	0.036	0.119	0.078	0.057
	G07	Doswell	171	0.033	0.130	0.082	0.057
	G22	North Las Vegas	197	0.030	0.178	0.089	0.058
	G28	Spanaway (Pierce Co., Wa.)			0.177	0.099	0.060
	G08	Gordonsville/Turbo Power I and II	128	0.043	0.116	0.079	0.061
	G19	Panda	160	0.042	0.133	0.088	0.065
	G03	Brooklyn Navy Yard Central	254	0.031	0.176	0.103	0.067
	G25	Tiger Bay	299	0.028	0.198	0.113	0.070
	G23	Blue Mountain Power	338	0.022	0.215	0.119	0.070
	G09	Wallkill	268	0.034	0.179	0.108	0.072
	G02	Brooklyn Navy Yard B	277	0.036	0.194	0.115	0.075
	G01	Brooklyn Navy Yard A	278	0.036	0.195	0.115	0.076
	G10	Linden	266	0.041	0.192	0.117	0.079
	G06	Pedricktown	234	0.050	0.187	0.121	0.083
	G04	Holtsville	251	0.050	0.199	0.123	0.085
	G05	Dartmouth, Mass.	405	0.028	0.259	0.143	0.085
	G24	Enron	520	0.020	0.317	0.169	0.095
		Average	240	0.035	0.174	0.103	0.069
Peaker	P03	Hartwell	90	0.038	0.089	0.063	0.051
	P02	Commonwealth Atlantic	68	0.052	0.090	0.071	0.061
		Average	79	0.045	0.090	0.067	0.056
Wind	W03	Franklin & Somerset/Kenetech	0	0.056		0.056 (36% cf)	

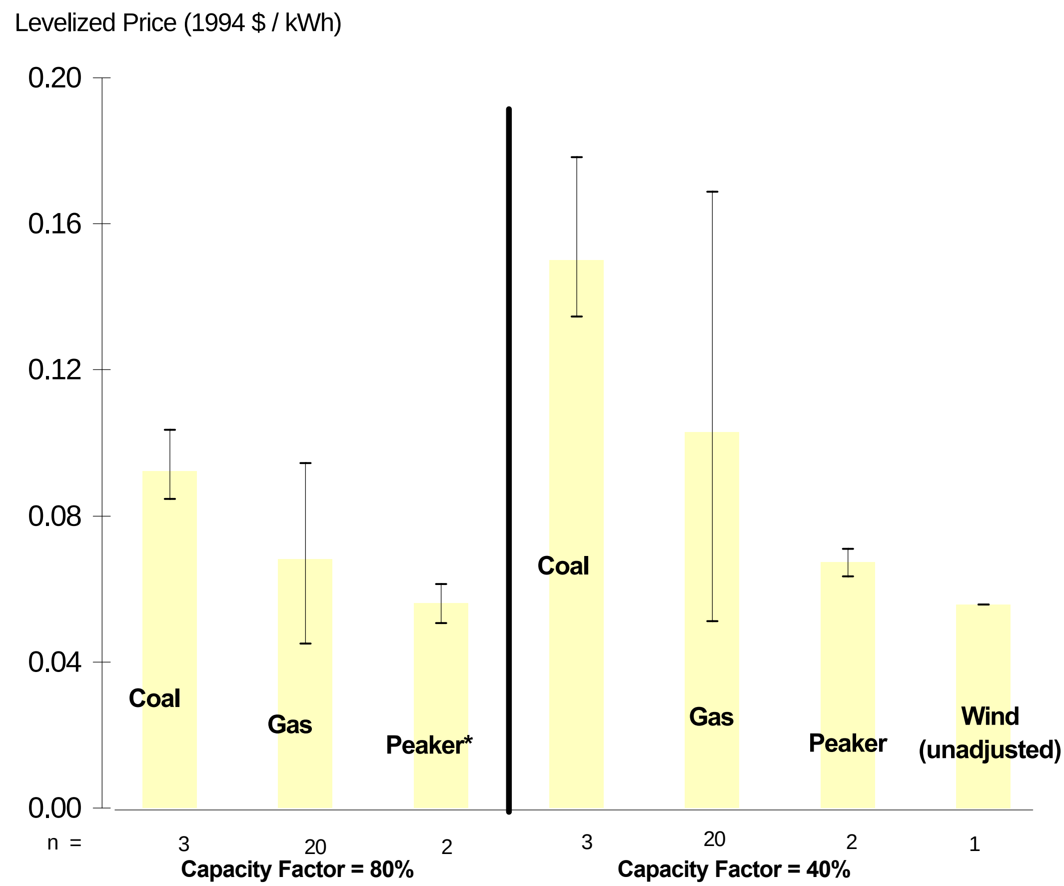
Notes: * Energy price evaluated at 80% capacity factor (cf)
Projects within each technology type are sorted by total price at 80% cf.
All averages are unweighted.

projects grouped into four technology types (coal, gas nonpeakers, gas peakers, and wind) and at two capacity factors; 80% and 40%. The figure shows that peakers are economically attractive in their expected niche (capacity factor = 40%) *and* at the 80% capacity factor. The three coal projects are generally not competitive except with the most expensive gas projects. It is important to reemphasize that the three coal projects have a different vintage than the gas nonpeaker projects; all of the coal projects have contracts executed from 1988 to 1990. Thus, changes in fuel markets and/or technological innovation, rather than differences in the technologies, may best explain the differences in prices.[12] Also, there is no consideration of

[12] Project prices are, however, adjusted to consistent fuel price escalation rates and consistent year's dollars.

fuel price risk in this comparison. How contracts handle fuel price risk is taken up further in Section 3.2.7, below.

Figure 3-1. Levelized Price by Technology Type



Note: Shaded bars indicate group averages. Line bars indicate group max/min values.
* See Sections 3.2.1 and 3.2.4 for a discussion of the anomalous peaker prices.

Figure 3-1 indicates that gas peakers are the cheapest projects at any capacity factor. Our sample size for peakers is small, and the low average price at the 80% capacity factor is primarily a result of the price for the Hartwell combustion turbine. Reasons that explain this apparently anomalous result are given in our discussion of screening curves, Section 3.2.4.

As part of checking our price analysis for accuracy, we were able to compare six operating projects to recorded prices for the year 1993 (see Section A.17). This analysis confirmed our price calculations reasonably well, but revealed that these projects are not operating within their expected dispatch niches. Four gas nonpeaker projects being sold to Virginia Power--SJE, Hopewell, Panda, and Doswell--operated in that year between 2% and 34% of their full capacity. Commonwealth Atlantic, a gas peaker purchased by Virginia Power, operated at a 5% capacity factor. Linden, a project with power purchased by Consolidated Edison, operated at a 65% capacity factor. Project literature for Linden indicates that it was expected to operate at an 80% capacity factor. As can be seen in Table 3-1 and Figure 3-1, actual prices for these projects rise considerably when capacity factors drop. These low capacity factors for dispatchable projects are a result of utility buyers facing lower demands for electricity and having cheaper economy energy available. Operating levels are likely to rise over time as the demand for power grows. The important lessons are, however, that expected and actual capacity factors can be very different and that pricing can play an important role in allocating the risk of demand uncertainty. In the case of these six projects, most of the demand risk is absorbed by the utility buyer, as price rises when capacity factors drop. An examination of Table 3-1 indicates that the allocation of demand risk to buyers via pricing has been used by all projects in the sample except Independence and the Kenetech wind project. These two projects are minimally dispatchable, however, so they have reduced demand risk in a different way.

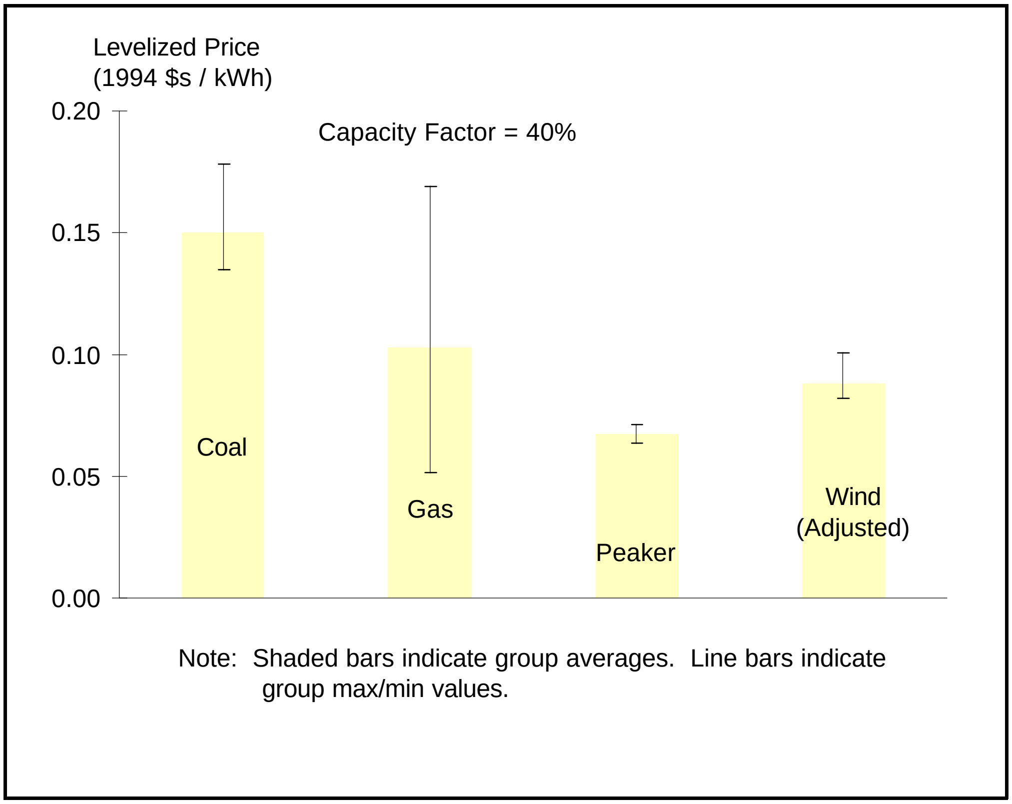
3.2.2 Adjusting Wind Prices for Intermittency

In Figure 3-1, the single wind project appears quite competitive. Its 20-year levelized contract price adjusted to 1994 dollars is \$0.056/kWh and is expected to produce electricity at a 36% capacity factor. At a similar capacity factor of 40%, thermal projects of any type are more expensive. However, for a proper comparison, one must adjust the wind price for its intermittent characteristics. Wind power does not provide the same on-peak reliability and dispatchability as the thermal projects (i.e., net dependable capacity for intermittent projects may be substantially less than nameplate capacity). In addition, intermittent projects may produce energy when it is not needed and may not produce energy when it is needed. We calculate a range of adjusted intermittent prices using different assumptions about the amount of backup thermal capacity and energy that is needed. In Appendix E, we develop a method that adjusts for the intermittent characteristics of renewable power like wind.

In Figure 3-2, we show a range of adjusted wind prices using this method and compare thermal prices at a similar capacity factor (40%). Our central estimate assumes that dependable wind capacity equals 25% of nameplate capacity and that backup energy is needed 25% of the time in order to achieve a 36% capacity factor at times when the energy is needed. This process produces an adjusted wind price of \$0.088/kWh. We also examined possible high and low price cases. For the high price case we assume that the intermittent wind project has no dependable capacity and that backup energy is required 45% of the time to achieve the target capacity factor, which produces an adjusted wind price of \$0.104/kWh. For the low price case we assume that the intermittent wind project's dependable capacity is 50% of nominal capacity and that backup energy is required only 5% of the time, which produces an adjusted wind price of \$0.072/kWh.

These adjusted prices for wind power are necessarily less precise than other prices we present in this chapter, as they rely on assumptions regarding the cost of backup power and make up energy, but they improve the accuracy of wind prices for purposes of comparison to thermal project prices.

Figure 3-2. Levelized Thermal Prices Compared to Adjusted Wind Prices



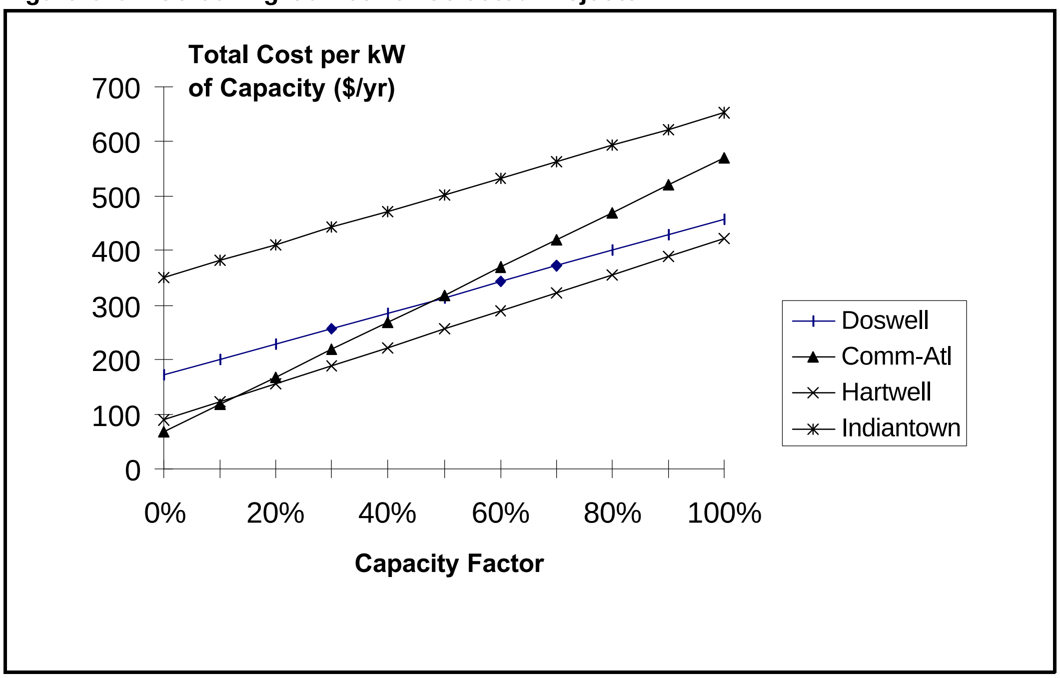
3.2.3 Comparing U.S. Prices to Prices in the United Kingdom

It is interesting to "check" prices for private power in the U.S. against prices from projects being developed from outside the U.S. We were able to obtain some price data on gas nonpeaker projects being developed in the United Kingdom (U.K.) from the U.K.'s Office of Electricity Regulation (OFFER). We compare our sample prices to prices for projects recently undertaken there. Total prices for U.K. projects were in the range of $0.057/kWh to 0.063/kWh. In our sample of 20 gas nonpeaker projects, four have levelized prices at or below $0.057/kWh and twelve projects have prices higher than $0.063/kWh. Thus, there is a reassuring amount of consistency between typical U.K. gas fired projects as reported by OFFER and typical U.S. projects as observed in our sample. We document our estimated levelized prices for the U.K. projects in Appendix C.

3.2.4 Screening Curves for Selected Projects

Relative prices for projects also vary by their capacity factor (see Table 3-1). A more complete understanding of the trade-offs between fixed and variable costs may be found by analyzing costs over a continuous range of capacity factors for a selected number of projects. The classic way to do this is through the use of *screening curves* (Stoll et al. 1989). In screening curves the total cost of operating a project, per unit of capacity, is computed at various capacity factors. Figure 3-3 depicts screening curves for a selected number of projects: two peakers (Hartwell and Commonwealth-Atlantic), one gas combined-cycle project (Doswell), and one coal project (Indiantown). Under a screening curve analysis, a planner should select projects that are least cost at a desired capacity factor. As discussed before, a project or technology that dominates at a particular capacity factor is within its dispatch niche. Again here, results are somewhat unexpected. Commonwealth Atlantic, a peaker, has the expected relationship with Doswell, a combined-cycle project: Commonwealth Atlantic is cheaper than Doswell below a 50% capacity factor and Doswell is cheaper at capacity factors greater than 50%. Virginia Power is the buyer of electricity from both of these projects, so it is reassuring to see each project having its own niche. Indiantown, on the other hand, is never competitive even though it is the cheapest coal project in our sample.

Figure 3-3. Screening Curves for Selected Projects



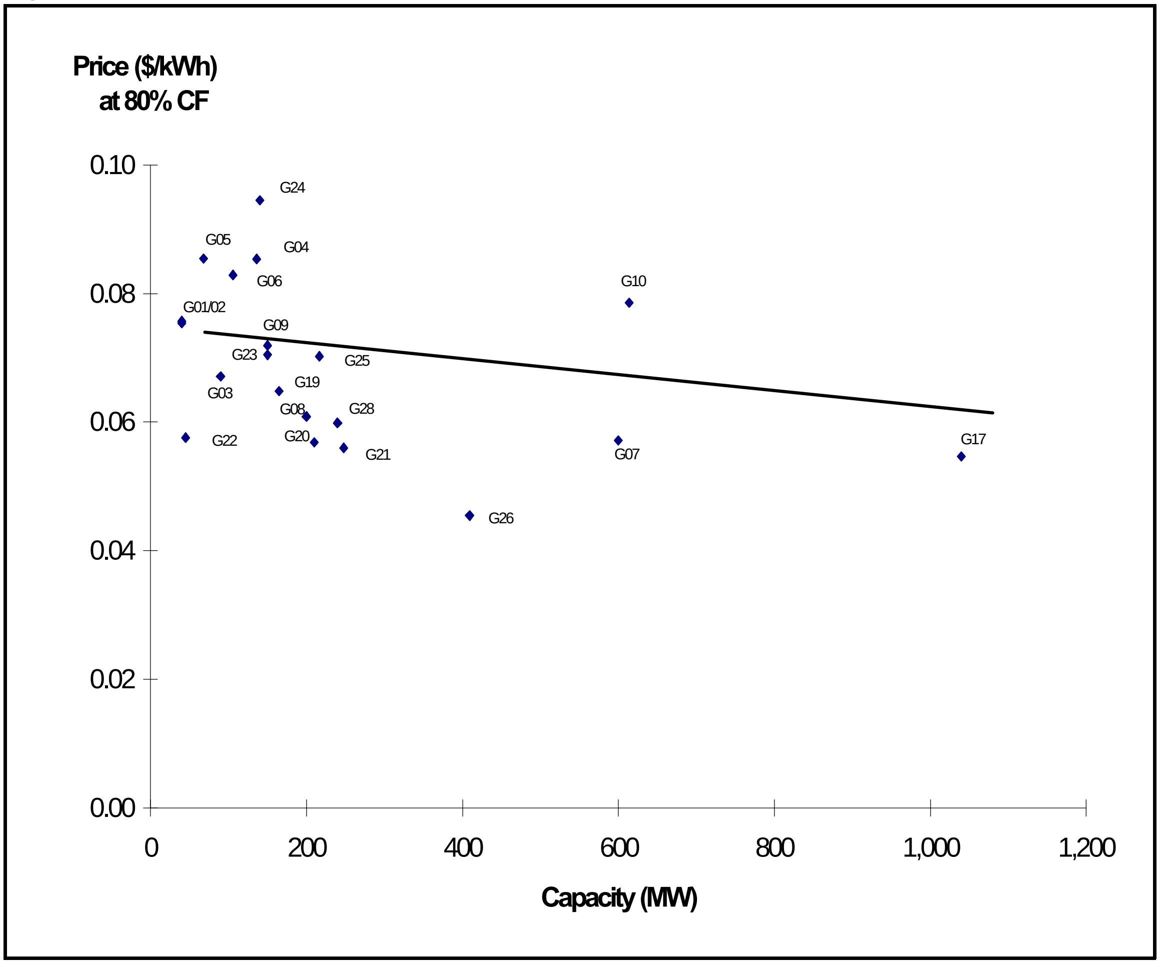
The Hartwell project provides the most anomalous results, as it dominates these screening curves. Based on this analysis, a planner would always choose a peaker like Hartwell, even for a baseload duty cycle. Although we believe that Hartwell's prices are important evidence of the current competitiveness of gas turbine technology, we do not believe that it represents a new dominant technology for several reasons. First, Hartwell's contract was executed in June 1992, so it represents one of the more recent projects in our sample and may be more cost competitive than other projects in the sample simply as a result of vintage. Hartwell's levelized demand charge of $90/kW-yr is relatively high for a combustion turbine but that higher fixed cost apparently allows for a more efficient turbine. Hartwell's Siemens turbine has a heat rate of 10,200 Btu/kWh, 12% more efficient than the heat rate of the Commonwealth Atlantic.[13] Second, Hartwell's buyer, Oglethorpe Power is a summer peaking utility and is acquiring gas supplies on an interruptible basis. A peaker like Hartwell will operate mainly in the summer, when gas and gas transportation is less expensive. In contrast, a combined-cycle gas project like Doswell must buy firm gas transportation capacity at an estimated cost of $30/kW-yr and that cost is included in its purchase price. Third, local air quality restrictions do not allow Hartwell to operate more than 2,500 hours/yr. This restriction indicates that the project has probably not included any expensive pollution mitigation technologies that may be a part of other projects in the sample. Because we do not believe that Hartwell's prices are directly comparable to intermediate or baseload plants we exclude peakers from our regression analysis presented later in this report.

3.2.5 Contract Prices versus Facility Size

The existence of scale economies is one factor that may help explain differences in prices (i.e., large facilities could produce electricity at a lower unit price than smaller facilities). We visually test this hypothesis in Figure 3-4 by plotting 20-year levelized price against facility size for the gas nonpeaker projects. We also show the "best fit" regression line. Facility size does not always equal contract capacity because some projects have substantial site loads or have uncontracted capacity. In general, we found a better relationship between price and facility size than price and contract capacity; this is reasonable since we believe that the underlying relationship has to do with technological efficiency. The figure shows there is modest evidence of scale economies, although the relationship depends heavily on several larger (> 400 MW) projects like Independence (G17), Hermiston (G26), and Doswell (G07). The simple average price for the four largest projects is $0.059/kWh, 19% lower than the simple average price of the remaining projects ($0.072kWh). While it appears that more recent projects tend to be lower in price, they are not always "large." For example, North Las Vegas (G22) and Blue Mountain Power (G23) are recently executed contracts for projects that are on or below the price regression line with capacities below 200 MW.

13 We estimate that Commonwealth Atlantic's heat rate to be 11,620 Btu/kWh based on summer energy charge of $0.0217/kWh, a summer gas price of $1.841/MMBtu (both prices for 1992) and an assumed variable O&M charge of $0.003/kWh.

Figure 3-4. Levelized Price versus Facility Size

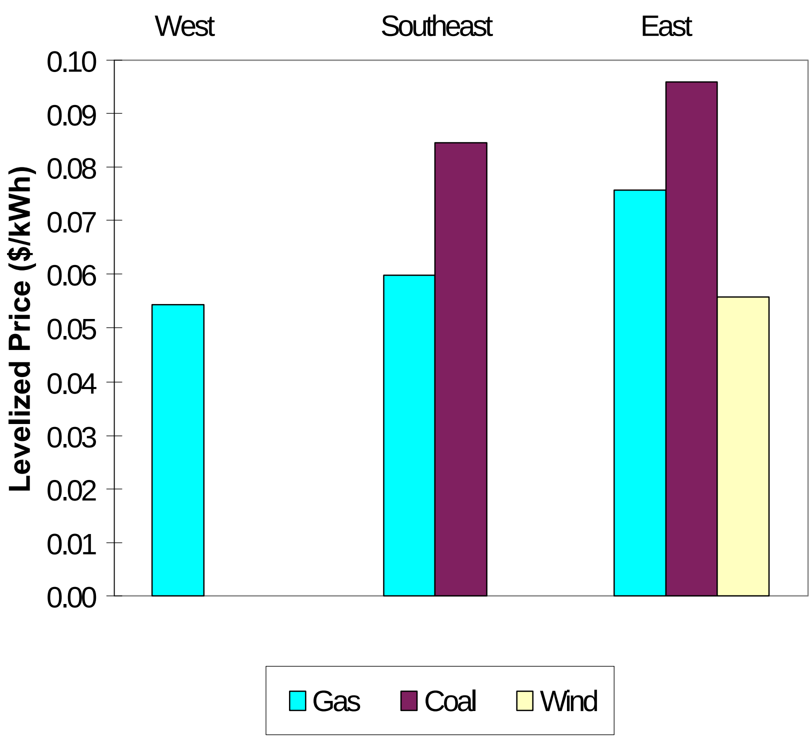


3.2.6 The Impact of Location on Prices

Regional Differences

Location also appears to play a crucial role in accounting for price differences (see Figure 3-5). We divided the sample of 26 projects into three regional categories: Northeast (n=14), Southeast (n=9), and West (n=3). The Northeast appears to have the highest prices, followed by the Southeast, and the West. This ranking applies to both coal and gas projects. There are a variety of reasons that could account for these regional differences. Electric transmission costs could be systematically higher in certain regions. Fuel transportation costs will differ depending upon the distance between the project and fuel source. Construction costs, operation costs, and taxes could differ by region. The Northeast certainly scores “high” with regard to all of these factors. It is also possible that some of the regional differences are a function of buyer willingness to pay. We believe that administratively-determined avoided

Figure 3-5. Levelized Price by Technology and Region



electricity costs are highest in the Northeast. High avoided costs are due, in part, to the higher environmental mitigation costs faced in that region, which are incurred by both utility and nonutility project developers. Thus, high contract prices in the Northeast could reflect both local cost factors or be a reflection of the fact that buyer value plays a role in the purchase price.

Linden versus Sithe: Can Transmission Opportunity Costs Alone Explain the Difference in Price?

A classic analysis of competition would require prices between any two points to be limited to the cost of transportation between the two areas. In our Stage I report (pp. 22), we found price differences that exceed the long-run cost of transmission. New projects in our sample continue to exhibit differentials in excess of long-run transmission costs. The Independence and Linden projects provide a good example. Con Edison is the buyer for both projects. Both are large combined cycle facilities and both projects' prices were the result of negotiation, although neither project was selected via a formal bidding process. Both projects originally had minimal dispatchability, although Con Edison and Linden have since negotiated contract modifications that now make Linden partially dispatchable. At a capacity factor of 80%, we estimate levelized price to be $0.079/kWh for Linden and $0.055/kWh for Independence--Linden costs 45% more than Independence. The difference in price is predominantly due to Linden's higher fixed charges. Compared to Independence, Linden's fixed-cost price components are $168/kW-yr higher than Independence's or, on a present value basis, the difference is approximately $1,500/kW. Several factors appear to contribute to this price difference.

With respect to transmission access, Linden, although not in Con Edison's service territory, is within the transmission "loop" that surrounds New York City. Independence is in upstate New York and requires wheeling by Niagara Mohawk Power Co. (NMPC). NMPC will wheel Independence's power to Con Edison at a price of $18/kW-yr (equivalent to $156/kW) but this cost is paid for by Sithe and is already included in its sale price. To get an estimate of the upper bound on the long-term cost of transmission, one may look at the RFP for power that Con Edison issued in 1990. In that RFP, Con Edison released scoring parameters that give an indication of the incremental cost of connecting out-of-area generation; out-of-state projects that required construction transmission facilities are penalized $1,277/kW on a present-value basis (Goldman et al. 1993, pp. 42, adjusted to 1994 $s). Even if this figure is accepted as an upper bound, location cannot solely explain the price difference among these two projects.

Apparently of equal or greater importance than transmission costs, is the role of Linden & Sithe's contract terms that treat fuel price and inflation risk. The two projects have very different provisions regarding energy and operation and maintenance (O&M) expenses. Linden's energy price provisions are complex, but essentially require Con Edison to buy electric energy based on an average of actual and indexed gas prices; apparently, Linden is not at risk for maintaining a specific heat rate. Further, Linden's O&M costs are charged as a fixed cost to Con Edison. Thus, Linden takes on some gas purchasing risk but faces only limited risk if the market price of electricity or demand for its project falls.[14] In contrast, Independence's total price is largely based on marginal energy costs (MECs) as adopted by the New York Public Service Commission. Approved MECs have fallen between the time of Independence's latest contract revision (December 1992) and commercial operation (November 1994). Further, we assume that future MECs in New York will be a function of natural gas and coal prices--not just natural gas prices as is the case for Linden's energy prices. The combined effect of the different energy and O&M pricing provisions between the two projects leads to a substantial difference in price.

This specific comparison of two projects underscores the difficulty of systematically explaining price differences. Differences in the definition of the product or its location appear inadequate in explaining price. In this case, it appears that the context of the negotiations (e.g., the utility's perceived resource need) and regulations at the time of

[14] Con Edison can curtail Linden on a limited basis. See Appendix A.

contract execution play a role. In particular, we believe that Con Edison's avoided costs, or willingness to pay, may have played a role.

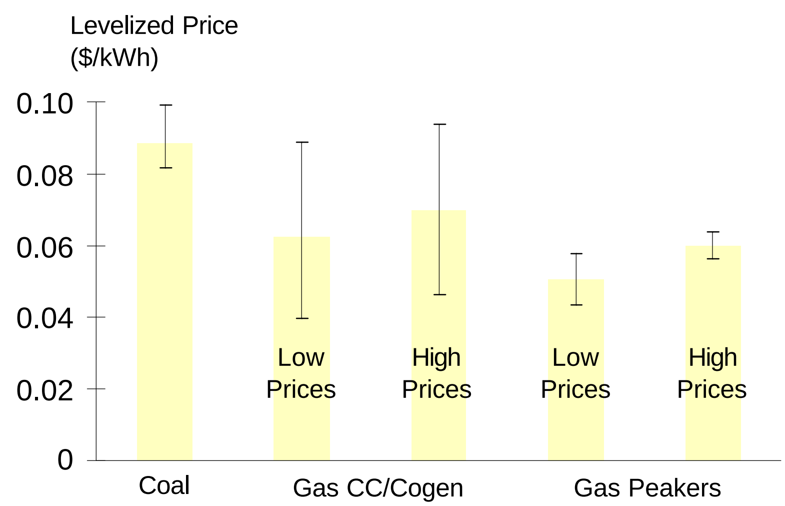
3.2.7 Contract Prices and Allocation of Fuel Price Risk

Fuel price risk is becoming an important term of trade in the private power market. This is clear in the comparison of Sithe and Linden. We examine price risk provisions of the gas nonpeaker projects more systematically in this section. We characterize fuel price risk in two ways. First, we compute prices in the sample under different fuel price expectations. Second, we qualitatively review gas nonpeaker contract provisions with respect to fuel price risk. We show these prices graphically and constructed the variable *PVAR*, which is an index that measures sensitivity to natural gas price changes, for use in our statistical analysis.

Effect of Gas Price Escalation Rates on Levelized Price

In most contracts, variable payments (or energy payments) are largely a function of fuel prices. Accordingly, the levelized prices that we report depend upon our assumptions about future fuel prices. Because it is reasonable that buyers may be risk averse, we might expect there to be a relationship between expected price and prices under less-than-expected fuel price conditions. Uncertainty over natural gas prices has certainly received the greatest attention in recent years, especially since electric generators in the 1990s have begun to rely more heavily on the fuel for the first time since the early 1970s. We might expect that gas projects, although cheaper than coal, place fuel-driven price risk upon the buyer. While gas

Figure 3-6. Range in Contract Prices Under Various Gas Price Forecasts



Note: Shaded bars indicate group averages.
Line bars indicate group max/min values.

projects are sensitive to fuel price changes, Figure 3-6 shows that this risk does not explain away the coal-gas price differences. Throughout our analysis, coal prices are assumed to escalate at inflation (4.1%/yr). Our low and high gas price cases assume that gas prices escalate at 2.1% and 8.1% per year (in nominal terms) respectively, compared to the basecase situation, which assumes a gas price escalation rate of 5.1%/yr. Even under this wide range of gas price escalation rates, only the most expensive gas nonpeaker projects rise to equal the coal prices.[15]

Allocation of Fuel Price Risk in Contracts for Gas-Fired Projects

Although the risk associated with fluctuations in future natural gas prices is a point of concern to buyers, this risk does not necessarily have to be passed through to the buyer. The insensitivity of gas-fired projects to increases in natural gas prices is because many of the gas-fired contracts have insulated the buyer from natural gas price risk. Ten of the 22 gas-fired projects have electric energy pricing terms that are *not* tied to natural gas prices (Table 3-2). Of these gas projects not directly tied to natural gas prices, four (Brooklyn Navy Yard A, B, and Central, and North Las Vegas) projects are tied to general price (inflation) escalators, three (Blue Mountain Power, Hermiston, and Spanaway) have fixed escalators that are defined in the contract,[16] and three (Independence, Enron, and Tiger Bay) are indexed to utility avoided costs. Of the three "avoided cost" contracts, Tiger Bay's pricing is explicitly tied to the operating costs of existing coal plants in Florida; thus it is clearly decoupled from gas prices. Enron's energy prices are based on the average cost of fossil-powered electric energy for the New England Power Pool. Other than a base-year value, we did not have an explicit forecast of these pool prices, so we assumed that the base-year value would escalate in parity to natural gas and coal prices averages using weights of 75% and 25%, respectively. Independence's energy prices are tied to short run avoided costs in New York. We used a recent long-term avoided cost forecast as the basis of our modeling of Independence's prices, but escalated these avoided costs in close parity with the gas-coal price index constructed for Enron.

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15 As has already been noted, an important qualification of this comparison is that the contracts for the three coal projects were signed in 1988 and 1990 and over one half of the gas contract were signed during or after 1991. Thus technological and economic changes over time may explain some of the large difference in price.

16 As noted in Table 3-2, Hermiston's prices after year 15 are tied to gas prices.

Table 3-2. Gas-fired Projects with Prices Not Directly Tied to Natural Gas

Project Name	Project I.D.	Energy Price Escalation in Contract	LBL Modeling Method
Brooklyn Navy Yard A, B, and Central	G01, G02, G03	GNP-PI	Generic inflation index used
Independence	G17	NY PSC Short-Run Avoided Energy Costs	Avoided costs forecast based on recent NY PSC order and a weighted-average escalator of natural gas and coal prices.
North Las Vegas	G22	80% of CPI-U	80% of generic inflation index is used
Blue Mountain Power	G23	Fixed escalation: 5%/yr through 2011; 9%/yr thereafter	Indexed per contract
Enron	G24	Weighted New England Power Pool Fossil Energy Cost	Base year price escalated using a weighted-average escalator of natural gas and coal prices.
Tiger Bay	G25	Operating costs of existing coal units	Escalation assumed equal to our generic coal index.
Hermiston	G26	Fixed escalation: 5.5%/yr for first 15 years; indexed to gas prices years 16-30	Indexed per contract for first 15 years; used generic gas index thereafter.
Spanaway	G28	Fixed pricing schedule for contract term (20 years)	Indexed per contract

These ten projects shown in Table 3-2 include *all* the fossil projects signed during or after 1991, except for Hartwell. Thus, it appears that the nonutility bulk power market has found ways to price gas-fired electric power without subjecting the buyer to fuel price risk. This risk mitigation has apparently been provided with little evidence of a price premium.

Although these contract terms have insulated the buyer from a substantial amount of gas price risk, the underlying risk of fuel price variability has not gone away. Instead, it has been taken on by the seller. There are several ways that sellers can mitigate the fuel price risk from their side. Although not apparent in our sample, developers can charge a premium for pricing terms that index gas-fired projects to things other than gas and use the premium revenues to build a reserve to help “ride through” periods of low or negative operating margins. Another strategy is for the seller to buy assets that rise in value when project margins are low or negative. Specific strategies include developers buying natural gas reserves, hedging in natural gas futures markets, or investing in coal gasification technologies. In all three cases, the developer will have an asset that will be most valuable when the market price for natural gas is high and project margins are low. Destec is clearly a leader in this regard. It has purchased natural gas reserves in association with Tiger Bay, and is also a developer of coal gasification technologies. While not economic today, coal gasification provides a hedge against future gas price volatility.

3.3 Preliminary Statistical Analysis

One of our primary objectives is to explain the observed variation in contract prices. In this section, we begin with a conceptual discussion that draws upon the relevant economic theory. We then develop a data set of explanatory variables and use correlation analysis and regression models to analyze the price data. Although our sample is small, the results of this preliminary statistical analysis tend to confirm the importance of factors identified in section 3.2.

3.3.1 Conceptual Approach: Theories for Explaining Variations in Prices

A simple textbook definition of a competitive market requires that there be one price for every product in the market (Sichel 1977). Differences in prices between geographic areas should be no greater than the cost of transportation between the areas. By this simple model, a market could be tested for competition by seeing whether a market obeyed the law of one price. Using this simple model of competition, the prices in our sample indicate a lack of competition, because, as noted in Section 3.2.6, levelized prices for power vary both between regions and within regions to a degree that exceeds the long-run cost of transmission. Even if one does not have good numbers on the cost of transmission, using this simple model of a competitive market, one may study competition by attempting to explain prices as a function of local cost conditions. If prices can be explained by objective measures of local cost, then there is evidence of competition. If they cannot, some sort of market inefficiency may exist.

A more accurate representation of real-world competition, however, recognizes price variation or discrimination even in competitive markets (Borenstein 1985). One can easily point to markets that have little barriers to entry and are generally considered competitive (or at least do not require price regulation) and see significant price variation: magazine subscriptions, movie tickets, and hotel rooms, to name a few instances. In these markets, price discrimination occurs--that is, a buyer s value has a role in determining price--but arguably market power is not being unduly exercised. Such markets are termed monopolistically competitive (Scherer 1990). A key factor that facilitates price discrimination in monopolistically competitive markets is product heterogeneity. Differences in quality or brand preference may be highly or loosely correlated with willingness to pay. If so, sellers of a product will generally charge more by emphasizing quality differences or brand attributes. So long as there are not formidable barriers to entry, however, discriminating by price is not necessarily inefficient.

Electricity is clearly a product with important quality or nonprice attributes. Electricity provides an essential service and cannot be cheaply stored; thus, reliability is a critical attribute. Location and generation technology can affect a power system s voltage, levels of reactive power, and stability. Another important nonprice attribute is a project s dispatchability. Dispatchable projects are better able to match variations in a buyer s loads and to minimize a buyer s system costs. Unless we quantify each project s impact on buyer value with respect to these nonprice factors, we cannot explain all reasonable sources of price variation.

At best, we can use a statistical analysis of prices to support a hypothesis of product heterogeneity and to look for evidence that *might* indicate market inefficiencies or market power. In other words, we cannot at this time establish whether competition is adequate or whether prices are excessive. However, we can test whether factors that we expect to influence price, in fact do so. The following sections describe some of the factors that we considered to be potentially significant determinants of price.

3.3.2 Factors that Explain Prices

We identify four general categories of factors that could reasonably be expected to have an influence on contract prices: product heterogeneity, geographic heterogeneity, technical and economic change, and other buyer attributes (see Table 3-3). Using readily available sources of information, we identified 15 independent variables that we expected to have an influence on contract prices, and classified them by category (see Appendix D for a more detailed description of the independent variables).

Table 3-3. Prior Expectations on the Meaning of Independent Variables

	If Independent Variable Significantly Explains Price, it Indicates Existence of:			
Independent Variables	Product Hetero-geneity	Geographic Hetero-geneity	Techno-logical & Economic Change	Importance of Other Buyer Attributes, Including Willingness to Pay
Facility Size	X			
Contract Term	X			
Technology and Fuel Type	X		X	
Dispatchability	X			
Buyer Exposure to Fuel Price Risk	X			
U.S. Geographic Region		X		
Coal Prices Available to Buyer		X		X
Gas Prices Available to Buyer		X		X
Distance to Gas Source		X		
State Income Levels		X		X
Local Economywide Prices		X		X
Interest Rates			X	
Contract Execution Date			X	
Commercial Operation Date			X	
Average Rates of Buyer				X
Annual Sales of Buyer				X

X = primary expectation (other relationships, of course, may exist)

Product Heterogeneity

As noted in Chapter 2, we limit our bulk power sample to privately-developed (nonutility), facility-based projects with contracts that were the result of some sort of competitive process. Even with these limiting criteria, considerable product heterogeneity exists. We identified five factors that contribute to product heterogeneity: dispatchability, dispatch niche, size, term, and fuel price risk.

Dispatchability. Because of the limited degrees of freedom in our sample, we simplify our dispatchability variable to a binary one: one value indicates full dispatchability and the other value indicates partial or minimal dispatchability (see section 2-1). All other things equal, we would expect fully dispatchable projects to command a higher overall price given their added value to the buyer, although we would expect the seller to offer a low variable or energy price to increase the chance of getting dispatched. The value of dispatchability is likely to vary from buyer to buyer.

Dispatch niche. Because we conduct our statistical analysis at a fixed capacity factor of 85%, we would expect base load plants to have a lower price than intermediate or peaking plants. Unfortunately, we had no way to accurately characterize intended dispatch niche, so we relied on proxies based on basic technology and fuel type designations, namely coal, gas nonpeaker (gas combined-cycle and/or cogeneration), gas peaker (gas combustion turbines), and wind (the only renewable project in the sample). Further, because the wind project is intermittent and one of the two gas peaker projects operates without a firm gas supply, we included only the former two fuel/technology designations in our statistical analysis.

Project size. While it seems intuitively reasonable to consider size as an explainer of price, economic theory would suggest that it should be irrelevant. If price is negatively correlated with size, why do small projects get built at all? The answer may be that smaller projects fit some buyers resource needs better. For example, a small electric power system may want to buy power from multiple small projects rather than one large project because smaller projects can provide greater reliability than a single large project. Perhaps, and more likely, smaller utilities face institutional barriers to buying into big projects. Bigger projects may bring lower unit costs but require a smaller utility or the developer to find co-buyers and require the execution of more complex contracts. Although it appears that project size will remain a significant indicator of contract price, it is unclear whether the observed premium paid for smaller projects is a reflection of a heterogeneous product sold in a competitive market or is a reflection of an inefficient industry structure.[17]

Contract term. Projects in our sample have terms ranging from 20 to 40 years. It seems natural that term would have an effect on price and we include it in our analysis.

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17 Studies suggest that the efficiencies in resource integration and dispatch would be achieved if smaller utilities consolidated. The estimated benefits of consolidation come from, in part, the ability of larger utility buyers to buy into larger projects and take advantage of economies of scale in generation (Hartman, 1990).

Fuel price risk. As discussed in Section 3.2.7, we constructed a variable, PVAR, that examines the sensitivity of the price of power to fluctuations in the rate of growth in the price of natural gas. PVAR is defined further in Appendix D.

Geographic Heterogeneity

In a very real sense, the geographic scope of the market for bulk power is global. Private power developers and equipment vendors compete for contracts with utilities from all over the world. ltimately, however, bulk power is sold to individual utilities with specific service territories. Ideally, we would specify synchronized transmission areas as bulk power markets and expect prices within these markets to be limited to the cost of transmission between points in the markets. We have already shown that price differentials exceed estimates of transmission costs, so we did not attempt to define electricity markets in terms of transmission areas. Instead, we considered factors that characterize the location of the seller or the service territory of the buying utility.[18] These variables include a simple regional designation (Southeast, Northeast, and West), and the local coal and natural gas prices available to the buyer. We constructed another variable that is an indicator of natural gas prices, namely the distance of the project from its gas source. This variable may be considered a proxy for seller natural gas transportation costs.[19] Local construction cost, labor costs, and taxes could be important factors, and we used general economic data on prices and incomes as a proxy. Air quality or other environmental restrictions in the region of the seller or buyer could also be an important factor, but we were unable to develop a specific environmental explanatory variable to account for them.

Technicological and Economic Change

Contracts in our sample were executed during the seven-year period from 1987 to 1993. It is conceivable that changes in prices may have occurred because of significant economic or technicological changes affecting the bulk power market. For example, private power project costs are sensitive to interest rates and changes in interest rates could change a competitive equilibrium price at any point in time. Technological changes occurred during our time frame as well. The dominance of the gas turbine as a prime mover has only grown in the past six years, in part because of improvement in the technology and greater confidence in the availability of gas fuel supplies. It is hard to measure technological change directly, but reasonable proxies include dates of contract execution and project

[18] In most cases, the location of the buyer and seller are the same or very similar. Exceptions include two projects where Con Edison is the buyer: Independence, located in upstate New York; and Linden, located in New Jersey.

[19] We could not use "Distance to Gas Source" in our final regression analysis because our dependent variable set includes both gas and coal projects. In any event, preliminary gas-only regressions indicated that the variable was insignificant.

operation. A project s technology type may also reflect technological change as well because a dominant position for a particular type of technology may indicate relative technological improvement compared to competing alternatives.

Other Buyer Attributes

Product and geographic heterogeneity and technological and economic change manifest themselves, in part, in differences among buyers. It is also possible that other characteristics of the buyer affect price. The most interesting buyer characteristic to test would be avoided cost, which is a measure of the buyer's willingness to pay. If avoided cost has a significant role in explaining price, several things may be going on. First, there may be aspects of product and geographic heterogeneity that we have not normalized for. Second, we may have a market where considerable price discrimination is occurring as a result of product heterogeneity or brand preferences. Third, it may be an indication of market inefficiencies or market power on the part of the buyer. Unfortunately, as interesting as the relationship of avoided cost and price may be, we were unable to collect avoided cost data for each utility. Instead, we used such proxies as income levels of residents in the service territory of the buyer, buyer retail rates, buyer location, and buyer fuel costs.

3.3.3 Statistical Analysis: Preliminary Results

Our general approach to the statistical analysis was to study the relationship of total price (20-year levelized) to the various explanatory variables. Our sample contains the 23 nonpeaker fossil projects, of which three are coal projects and twenty are gas projects.

Correlation Coefficients

In Table 3-4, we show simple correlation coefficients between price and all the variables identified in Table 3-3 for which we were able to obtain a complete data set. The six most significant variables based on simple correlations are: local coal prices, Northeast integer (dummy) variable, state income levels, coal project integer variable, sales of buyer, and facility size. These correlations indicate which variables are likely to be significant in a multivariate regression.

Table 3-4. Variable Definitions and Correlation to Total Price

Variable	Correlation With Total Price (TP)	Definition
Total Price (TP)	1.00	Twenty-year levelized price in $ / kWh.
Coal Prices (COALPRC)	0.76	Average price of coal in state of buyer for 1991 and 1992, expressed as cents per MMBtu.
Northeast Project (NE)	0.63	One of two dummy variables used to differentiate between projects in the Northeast, Southeast, and West. NE equals one for projects in Northeast and zero for other projects.
State Income Levels (SII)	0.59	Index of median family income in state of purchasing utility.
Coal Technology (COAL)	0.55	Dummy variable differentiating coal and gas-fired combined cycle projects. COAL equals one for coal projects and zero for gas projects.
Annual Sales of Buyer (SALES)	-0.52	Annual sales of purchasing utility in MWh.
Average Rates of Buyer (RATES)	0.43	Average retail rate of purchasing utility, measured in $ / kWh.
Interest Rates (TRATE)	0.34	Yield on ten-year treasury on date contract was signed.
Southeast Project (SE)	-0.34	One of two dummy variables used to differentiate between projects in the Northeast, Southeast, and West. SE equals one for projects in Southeast and zero for other projects.
Facility Size (TCAP)	-0.31	Dependable summer capacity of project in GW.
Contract Term (TERM)	-0.30	Length of contract in years.
Dispatchability (DSP)	-0.20	Dummy variable differentiating fully dispatchable and all other projects.
Price Risk (PVAR)	-0.14	Variable constructed to measure the sensitivity of total price changes to changes in natural gas escalation rates. The more sensitive total price is to changes in escalation rates, the higher the PVAR value.
Contract Execution Date (CED)	-0.13	Date that power purchase contract was signed, measured in days using Excel's date function.
Gas Prices (GASPRC)	0.03	Average price of natural gas in state of buyer for 1991 and 1992, expressed as cents per MMBtu.

Regression Analysis Methodology

Our general strategy was to find the best, most parsimonious regression equation for explaining price. By “best” we mean regressions that provide the most explanatory power, adjusted for degrees of freedom. A “parsimonious” regression excludes variables that do not provide much residual explanatory power. We were careful to exclude a variable only if excluding it did not bias the coefficients of the remaining variables.

We tested many models using total price, fixed price, and energy price as explanatory variables. Because of the small sample size, we ended up focusing on total price. While we believe regression analysis is a useful way to understand relationships in the data, all findings and conclusions based on the regressions should be considered preliminary given the small sample size.

Regression Analysis Results

Based on a systematic search for significance across our set of explanatory variables, the following regression best explains total price in the most parsimonious manner:

$$\underset{}{TP} = \underset{(1.7)}{0.023} - \underset{(-2.5)}{0.012 \cdot TCAP} + \underset{(3.8)}{0.014 \cdot COAL} + \underset{(4.9)}{0.0004 \cdot COALPRC} - \underset{(-3.0)}{0.0006 \cdot TERM} + \underset{(5.6)}{0.013 \cdot NE}$$

$$\text{Adjusted } R^2 = 0.88$$

where variables are defined in Table 3-4 and t-statistics are in parentheses. Other than the intercept, all of the variables in the regression may be accepted at the 97% confidence interval.

Based on the regression, we make the following preliminary conclusions:

- The costliness of the coal projects is clearly reflected in the regression. A coal project, all other things being equal, adds \$0.014/kWh to a contract's levelized price.
- Prices are a function of local fuel costs. An increase in delivered coal prices of \$0.50/MMBtu increases levelized electricity prices by \$0.019/kWh. Interestingly, coal prices rather than gas prices (or both coal and gas prices) were found to be the most significant fuel variable despite the fact that all but three projects in the sample are gas-fired. We believe this is plausible because most buying electric utilities in our sample have coal-fired projects in their systems, so coal prices may be an important indicator of buyer avoided costs (willingness to pay).
- Scale economies are significant. Facility sizes in our samples range from 40 to 1,040 MW and the regression indicates that spanning that range (1 GW) adds \$0.012/kWh to the purchase price. This scale economy represents about one third of the mean capacity price of the gas nonpeaker projects at an 80% capacity factor (\$0.035/kWh).
- Projects in the Northeast add \$0.013/kWh to the purchase price relative to projects in the Southeast or West.
- By signing on for longer terms, buyers get a lower price. An additional ten years of contract term lowers total price by \$0.006/kWh. This result should be qualified somewhat because we use a 20-year levelized price as our dependent variable. This

result indicates that by buying longer-term, prices during the first twenty years are moderately lower.

A number of variables that have significant correlations with price as shown in Table 3-4 did not remain in the regression because they were collinear with one or more other explanatory variables.[20] For example, income of people in the state of the buying utility has a high correlation with total price but does not stay in the regression, probably because it is collinear with coal prices (correlation coefficient = 0.47). Interest rates at the time of contract execution are also collinear with coal prices (correlation coefficient = 0.71). Buyer sales and rates are collinear with the NE integer variable (correlation coefficient = -0.69 and 0.78, respectively).

We were surprised to see that dispatchability did not have a more pronounced effect on price. It is poorly correlated with price and is insignificant in the regressions. Certainly, dispatchability has value but it has not resulted in price impacts. We are similarly surprised at the insignificance of PVAR. Again, to the extent our sample is representative, it appears that decreased fuel price risk comes for no extra charge in the current market.

[20] *Collinearity* is the linear correlation of two or more independent variables.

Discussion

4.1 Introduction

In this chapter we discuss the policy implications of our major findings, including contract disclosure issues.

4.2 Access to Contracts: The Problem of Confidentiality

The primary purpose of this report is to collect and analyze data on prices for private power, but the obstacles encountered in collecting PPAs lead us to address contract disclosure policy. There were at least ten projects with contracts that met our criteria for inclusion but were unavailable because existing state and federal policies explicitly or implicitly allowed them to remain confidential.[21] These contracts represent about 1,300 MWs of non-utility capacity acquired through competitive processes, approximately 20% of our existing sample. This section discusses disclosure policies at state Public Utility Commissions (PUCs) and the FERC and then makes an argument for a policy of improved access.

4.2.1 Disclosure of QF Contracts by State PUCs for Investor-Owned Utilities

At least seven state PUCs that have or have had an active independent power industry require that executed QF or IPP contracts be made public: California, Florida, Massachusetts, Nevada, New York, Pennsylvania, and Virginia. At least one state PUC, New Jersey, formerly had a policy of making contracts public but now appears to allow contracts to remain confidential. Several state PUCs, including Washington, Oregon, Montana, and Wisconsin, currently support an active independent power market but do not require contract disclosure.

Because QFs are not public utilities under federal law, any government decision to make QF contracts publicly available rests with the state.[22] States can also affect the timing and disclosure of nonutility projects that have prices regulated by the FERC. Although all wholesale prices, including EWG prices, must be approved by and disclosed through the FERC, most state PUCs effectively review contracts entered into between IOUs and EWGs through resource planning proceedings or prudence reviews. At least one state,

[21] Of the ten confidential contracts we identified, nine were associated with QFs and one contract was for a project involving a buyer and seller in Canada.

[22] QFs are qualifying facilities as defined in the Public Utilities Regulatory Policies Act. Regulatory approval of prices paid by investor-owned utilities (IOUs) for power from QFs is made by state PUCs, although it is subject to FERC avoided-cost pricing guidelines.

Pennsylvania, requires that EWG contracts be made public as a part of its resource acquisition policies.

4.2.2 Publicly-Owned Utilities: Municipal Utilities and Federal Power Marketing Authorities

Disclosure of contracts entered into by municipal utilities (munis) varies widely. Many munis operate under public disclosure laws, but, because munis are not accustomed to justifying ratepayer benefits to independent regulatory commissions, some munis do not disclose executed contracts even if their charters technically require it. Currently, the closest any of the contract sample buyers comes to being a muni is Ogelthorpe Power Company, a generation and transmission (G&T) cooperative in Georgia. Because Ogelthorpe is buying from Hartwell (P01), an IPP, we were able to obtain the contract as a result of the seller's FERC filing.

Our contract sample also includes one contract (Tenaska, G28) in which the buyer is the Bonneville Power Administration (BPA), a federal power marketing agency. BPA makes a contract public after it is executed. Before that time, however, only limited pricing information is released. BPA has also entered into options contracts for certain supply-side resources. These contracts were not made available by BPA because the agency does not consider these contracts to be executed.

4.2.3 Disclosure by the Federal Energy Regulatory Administration (FERC)

Except for PURPA QFs, FERC approval is required for any power sold for resale (wholesale) in the U.S., including power from independent power producers. EPAct's creation of EWGs, along with the current advantages of non-QF combined-cycle generation technology, will accelerate an existing trend away from state regulation of private power pricing to federal regulation.

FERC authority to approve public utilities rates for power sold in interstate commerce, including sales from private developers, rests under Section 205 of the Federal Power Act. The regulations require that rates for such sales be filed no more than 60 days before the sale commences. In fact, when contracts are filed further in advance, the seller must ask for a waiver of FERC regulations. As a result, there are probably several IPPs with executed contracts that have yet to make a filing for approval of rates; we were able to obtain only three contracts via the FERC filings (Hermiston, Enron, and Hartwell). IPP developers that will probably not follow this last minute strategy are ones who are or might be affiliated with the buyer or ones that are perceived to have some sort of market power. In these cases, the FERC scrutinizes applications for market-based rates more heavily, so sellers in these cases have an incentive to file earlier. For example, the Hermiston project, which is not scheduled to be completed until July 1996, has already filed for approval of its contract with Pacificorp.[23] The project is co-owned by PG&E, which owns and controls transmission facilities near the project and there are provisions in the contract which allow Pacificorp to purchase the project. Both of these reasons may explain the early filing of this project.

4.2.4 LBL Recommendations Regarding a Policy of Public Disclosure

We believe policies that implicitly or explicitly preserve contract confidentiality impede the creation of a competitive bulk power market. Public prices improve both the value of bids made by developers and improve the decisions made by utility buyers and regulatory commissions. Unfortunately, despite the social benefits of disclosure, it appears that all decision makers in the industry--developers, buying utilities, and regulators--have short-term incentives to support confidentiality. Project developers have a natural incentive to keep prices confidential. Representatives of project developers have indicated that they believe the market for bulk power is less than fully competitive (Besser 1994). Thus, they believe there is a loss of market power or competitive advantage if confidentiality is lost. For example, project developers that successfully execute a contract that is then made public can expect that the contract will, in future negotiations, represent the starting point rather than a successful ending point. The losses from making future concessions appear to outweigh the possible gain in market share that a developer would experience.

Similarly, utility buyers do not have strong incentives to disclose contracts; they receive full price information from bidders and releasing contract prices only dilutes any market power they hold and opens themselves to second-guessing by regulators. Further, with the possibility of “direct access” (retail wheeling) increasing, disclosure of generation capacity and energy prices can increase large customers’ interest in bypassing the utility.

While the expectation of losses can explain the positions of developers and buyers, it is harder to justify the explicit or de facto policy of many state PUCs to allow for contract confidentiality. PUCs presumably serve the public interest but several commissions appear sympathetic to confidentiality requests because (1) the commission or its staff can get the information it needs to conduct an analysis of contract net benefits and (2) they appear to believe that disclosure will reduce the effectiveness of the bidding process. Individual participants in the bid process may complain of economic losses as a result of disclosure and sometimes argue that they will not participate in an open auction. From a societal perspective, however, these losses to individual participants should be outweighed by the gains low-cost bidders make in market share and an increase in welfare to consumers that benefit from lower cost power. Certainly, the benefits of contract confidentiality, if any, would only accrue up to the point in time when parallel RFPs by the same or similarly-situated utilities come to a close. At that point, there should be no reason not to make

[23] FERC has ruled on the Hermiston application and denied the applicant’s request for market-based rates.

contracts public. For state regulators that do not wish to make bid prices or contracts public, we suggest a balance between the possible private costs and the societal benefits of disclosure by advocating that contracts be released after a certain amount of time has passed.

Another way to improve disclosure policy is to improve the reporting of project prices once they become operational. FERC, for example, could make private power producers subject to the same statistical reporting obligations as public utilities. Currently, FERC-regulated utilities above a certain size are required to file Form ls with a breakdown of purchased power costs by seller.[24] QFs, EWGs, and smaller sellers of power have reduced reporting obligations. Current reporting requirements could result in a large number of unreported transactions in the future, especially if direct sales become more commonplace.

Other than changes in disclosure and reporting policies by state or federal regulators, the only other way that prices will become public is through the creation of publicly-traded spot and forward markets for electricity. In publicly-traded markets, price is the dominant carrier of information. Confidential negotiations to reveal pricing terms are too costly in such markets. Currently, spot and forward markets for electricity are in their most nascent stages. Further, they are not currently relied upon for long-term capacity needs. Although such markets will provide a valuable source of price revelation in the future, they will not substitute for prices as revealed in the long-term contracts market.

4.3 Summary of Major Findings and Discussion

Our levelized price calculations on our sample of contracts clearly indicate that gas technologies dominate. At an 80% capacity factor, coal projects cost an average of $0.092/kWh, which is higher than all but the most expensive of the natural gas-fired projects. The average price of gas nonpeakers is $0.069/kWh (80% capacity factor) but there is considerable variation. Two larger projects, Independence and Hermiston, have an average price of $0.050/kWh, which is 28% lower than the sample's average price. Further, the general dominance of gas-fired technologies is robust over a wide range of gas price escalation rates. Even if natural gas prices are assumed to escalate at 4%/year real, natural gas projects are generally cheaper than the coal projects.

The most surprising and perhaps anomalous result of our levelized price analysis is the apparent dominance of the gas combustion turbine projects (gas peakers). Gas peakers, with their low capacity costs but relatively higher heat rates, are intended to fill a niche at low annual capacity factors. Although the peakers are the cheapest gas-fired resources at a low capacity factor (40%), they are also competitive with gas nonpeaker projects at an 80% capacity factor. As we discussed in Chapter 3, there are reasons that make us believe the

[24] Some utilities in the past have reported all nonutility providers on one line. FERC staff have recently worked to rectify this situation and more detailed reporting should now be the norm.

peaker prices are not directly comparable to the other thermal prices because they may not have the same annual availability. Nonetheless, given that the market for gas combustion turbines has become highly competitive and the current price of natural gas, gas combustion turbines appear to fill a wider dispatch niche than they have in the past. Hopefully, more data on recent gas-fired projects will provide us with a better understanding of the respective niches of combustion turbine and combined-cycle facilities. With more data, we will be better able to control for factors such as gas supply reliability and environmental restrictions.

For the five gas nonpeaker projects already operational, current operating levels are considerably below those used when evaluating the projects during bidding or negotiation. Four projects purchased by Virginia Power have 1993 capacity factors of 2% to 34% and one project purchased by Consolidated Edison, Linden, operated at 64%. Demand risk, thus, appears to be important, and it appears that all sellers do a pretty good job of passing this risk on to the buyer.

Another important finding of our price analysis is that wind power appears to be competitive. As with other prices reported in the trade press, it is important to avoid comparisons using first-year prices. It so happens that the wind project’s levelized price is higher than its first year price. Also, the appropriate price for comparison is not the contract price because the availability of the wind resource is not the same as a thermal project. However, even after the levelization adjustment and the adjustment for backup energy and capacity, wind prices appear competitive with thermal projects.

In addition to technology type, fuel type, and size, we found several other variables to be critical in explaining price variations. Location matters; Northeast projects were generally the most expensive. Local delivered coal prices were significant. We believe that these two variables act as good proxies for buyer avoided costs. Term of contract also played a role.

It is also interesting to review what *didn t* matter in determining price. First, project prices did not correlate well with their dispatchability. Second, sensitivity of project levelized prices to fuel price variability did not appear to affect price. Coal projects are generally known for their stable fuel supply. Natural gas projects may be fundamentally susceptible to fluctuations in the price of the fuel, but *all* of the recent gas nonpeakers had variable-cost terms *not* directly indexed to the fuel. Our regression results indicated that buyers are able to protect themselves from gas price risk *apparently at no additional cost*.

In the end, price is not explained well by local cost differences. Buyer value appears to play a role. Electricity is not a homogeneous commodity; it has reliability and other quality attributes that are important to the buyer. It appears that some level of price discrimination is occurring. As evidenced by the location and local coal price variables, higher-valued projects appear to be coming in at higher prices. Price discrimination in a market is not necessarily bad. Although it is often associated with monopoly pricing and a loss of welfare, price discrimination can occur in monopolistically competitive markets when there is a congruence with buyer value and an easy-to-differentiate product attribute, such as location or reliability. So long as there are no significant barriers to entry, price discrimination will not necessarily result in a loss of welfare. Our model, unfortunately, cannot distinguish between "good" price discrimination (prices that do not significantly reduce total welfare) and "bad" price discrimination (seller market power is being exercised). Because of the remaining, unexplained price variability, we can offer little guidance to the electricity buyer or electricity policy maker. There is still no "one" price for electricity, at least not in the long-term contracts market. As a result, buyers will still need to conduct considerable research on recent contract prices to see if proposed bids are reasonable relative to recent experience in the marketplace. In other words, buyers will have to focus keenly on their avoided costs as avoided cost plays a role in determining price.

There are also implications for policy makers. They will have a hard time measuring the benefits of a competitive industry structure by observing prices. Instead, they will have to remain satisfied with policies and regulations regarding industry structure and conduct, such as keeping barriers to entry low and competitive acquisition processes fair. An implication of this will be that it will be difficult, at least initially, to identify market-based measures of prudence. Regulators will have to continue to rely on resource planning processes to determine what constitutes a reasonable resource as acquired by competition *or* simply accept that once a competitive market structure is created, the price resulting from the process will be de facto reasonable.

Despite the rejection of a homogenous product market for bulk power and the difficulty of measuring economic performance in heterogenous product markets, policy makers should not lose sight of some of the important benefits of competitive resource acquisition. Nearly all of the recently-signed projects are fully dispatchable. Many contracts are being written in a way that reduce buyer risk from potential future gas price increases. Neither of these benefits to ratepayers were common when state PUCs adjudicated avoided cost prices and other contract terms (Kahn 1991). Further project developers are taking advantage of a high degree of competition for turbines and other equipment and claim to be benefiting from a return to standardized project designs.

Some analysts have predicted that electricity will become more commodity-like in the future. If it does, price variation among contract prices should decrease. Continuing to measure prices and other contract terms will help policy makers evaluate this potential trend towards commoditization.

It appears that the U.S. market for new privately developed supply has slowed considerably, which along with disclosure policies, affects our ability to expand the sample. Many buyers in the market are going "short;" that is, they are entering into contracts with shorter terms. To facilitate short-term deals, several institutions and mechanisms are being created, such as a futures market, price publications, and financial contracts for mitigating price risk. The market for long-term contracts will not be forgotten; it represents a stable measure of the cost of expanding capacity in the future. We hope to collect, in future research, market-based contracts for bulk supply for a wider range of terms. By doing so, we will get a better sense of how the "mature" long-term market relates to emerging short-term markets.

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Description of Sample Projects and Purchase Power Agreements

A.1 Introduction

Our Stage I report included 11 contracts. This report includes 15 additional contracts, bringing our total sample to26. The following describes each of the fifteen contracts added to the sample in this report. Each section identifies the contracting parties and provides a brief description of the facility, its dispatchability, and its pricing. Following each contract's written description is a table showing multi-year prices and our calculations of levelized price. Projects are listed in alphanumeric order using the project I.D. codes identified in Chapter 2. For a description of sample contracts not included in this appendix, see Kahn (1993).

A.2 Gordonsville (G08)

Parties

Virginia Electric Power Company and Virginia Turbo Power Systems Two, LP

Facility Description

The Gordonsville project is a QF with 200 MW of estimated dependable capacity in summer (i.e., 90°F) and 132 MW in winter (i.e., 20°F). Commercial operation began in June 1994. Sales to Virginia Power are made under two contracts, which have identical pricing but can be dispatched separately.

Dispatchability

Virginia Power has the right to dispatch the plant, subject to the following constraints:

- Per contract, the facility is capable of operating over the continuous range from 0 MW to 154 MW for the winter period and 125 MW for the summer period.
- The facility cannot be operated in the range of 0 MW through 85 percent of dependable capacity except in an emergency.
- Once the facility has been synchronized with Virginia Power's system, its output may be increased or decreased at a rate not less than 2.3 MW per minute per contract.

Pricing

The Gordonsville contract has capacity, O&M, and energy prices. There are different energy prices for summer and winter months. The summer period includes the months of April through October; the winter period includes the months of November through March. We assume that the plant operates at the same capacity factor throughout the year. Accordingly, the total price equals the sum of capacity price, O&M price, and a weighted average energy price.

Capacity
The capacity price is fixed for the duration of the contract at $128 per kW per year.

O&M
The O&M payment equals 0.218 cents per kWh in 1988 dollars and escalates annually with the GNP implicit price deflator.

Energy
Like other Virginia Power contracts, the energy price is calculated as follows

$$Energy\ Price = Base\ Price \cdot \frac{Reference\ Fuel\ Index}{Base\ Fuel\ Index}$$

where the base price and the methodology for calculating the fuel indices are stipulated in the contract.

The base summer price equals 2.13 cents per kWh and is indexed to natural gas prices. The base winter price equals 2.92 cents per kWh and is indexed to oil prices.[25] The base indices reflect 1987 fuel prices, while the reference indices reflect fuel prices for the year in which electricity sales are made. Since commercial operation started in 1994, we estimated the 1994 energy price using actual fuel prices. This entailed a two-step process. First, we used actual 1993 fuel prices to calculate separate reference fuel indices for summer and winter. Using the base price and base fuel indices, we then calculated summer and winter energy prices for 1993. Second, we estimated 1994 prices by escalating 1993 energy prices for one year. We used "Inflation" as the escalator for winter prices and the gas "Spot" index as the escalator for summer prices. After 1994, energy prices are calculated by escalating the 1994 energy price using "Inflation" for winter prices and the gas "Spot" index for summer prices.

[25] Base and reference summer indices should be based on prices reported in Natural Gas Clearinghouse and Natural Gas Week. We used values reported in Natural Gas Monthly as a proxy. Base and reference winter indices should be based on the price of number 2 fuel oil reported in "Platt's Oilgram Report." We substituted number 2 fuel oil prices reported in Annual Energy Review.

A.3 Linden (G10)

Parties

Consolidated Edison and Cogen Technologies Inc.

Facility Description

The project will consist of four or five gas turbine units and associated waste heat steam generators arranged in combined cycle with one or two steam turbines. We understand that the project uses GE MS - 7000 turbines with heat rates of approximately 9,000 Btu/kWh. The contract indicates that the maximum expected capacity will be approximately 594 MW, but according to the buyer, the contract capacity of the now-completed project is 614 MW. The contract will be in effect for 25 years and can be renewed for two periods of five years. Since either party has the right to terminate the contract after the initial 25 year period, we have excluded the ten year extension from our analysis.

Dispatchability

Energy purchases are subject to limited curtailment by Con Edison. In 1993 these curtailment provisions were modified as an outcome of the ongoing NY PSC proceeding on QF dispatchability (PSC Case 88-E-081). During the first fifteen years, the buyer can generally curtail energy deliveries down to 82 percent of output during weekdays and 47 percent of output during weekends. In addition, the buyer can curtail deliveries down to 59 percent (= 82 percent - 150 MW) for 100 nights a year. During the last ten years of the base contract, the buyer can curtail energy payments to 47 percent of output.

Pricing

Capacity
The capacity charge is fixed for the life of the contract at 1.8553 cents per kWh multiplied by annual hours of operation up to an 85 percent capacity factor. Any hours that the facility is not running due to curtailment shall be included in the capacity charge. We assume that the seller is capable of operating above an 85 percent capacity factor, thus the annual capacity charge equals 1.8553 cents per kWh times contract capacity times 85 percent of possible operating hours, or $138/kW-yr.

Fixed O&M
The nominal O&M price equals 0.9 cents per kWh as of December 1988 and escalates using a New York - Northern New Jersey regional CPI. We use our general inflation index as a proxy. The contract states that the seller will receive an O&M payment for all hours that it is capable of operation up to a 90 percent capacity factor, including curtailed hours. We assume that the seller is capable of operating at a 90 percent capacity factor, thus the O&M

payment is a fixed annual payment that escalates with inflation. Because of the fixed nature of the O&M payment, we treat it as a capacity cost for purposes of our regressions.

Fuel

The fuel price is based on actual fuel costs of the Linden plant, with a base-year (1989) ceiling price of 2.634 cents per kWh. The ceiling price changes annually based on the ratio of actual gas prices for the current year and 1989. The contract allows for a reconciliation wherein half of the difference between the cost ceiling and the actual operating costs are returned to the buyer. Because the plant has been operational since 1992, we know from FERC Form 1 that the average energy cost ($/kWh) of the project for 1993. Further, according to the buyer, the project's heat rate is between 9,000 and 9,500 Btu/kWh and that the 1993 recorded costs did not include a significant amount of reconciliation dollars. Because the contract provides little guidance regarding the project's actual electric production costs, we decided to calibrate the energy price so that the project's price would match the FERC Form 1 data for 1993. At an assumed heat rate of 9,000 Btu/kWh, the 1993 cost of gas must equal $3.50/MMBtu to match the FERC Form 1 data. This price is escalated upward and downward to compute prices for the rest of the years in the contract.

A.4 Independence (G17)

Parties

Consolidated Edison Co. and Sithe/Independence Power Partners, L.P.

Facility Description

The Independence project is a natural gas-fired cogeneration facility having a design capacity of approximately 1,040 MW. The project will be located on the shore of Lake Ontario near the town of Oswego, NY. An industrial plant (Alcan) nearby will be a steam customer. The facility will consists of four G.E. Mod MS7001FA combustion turbines of 160 MW each and two steam turbines with capacities of 208 MW each.

The project has three purchase power contracts. The biggest is with Consolidated Edison (Con Edison) for a summer adjusted capacity of 740 MW. The project will also sell power to Alcan (44 MW) and up to 3 TWh/yr of energy to Niagara Mohawk Power Co. (NMPC). This energy is available as a result of 300 MW of uncontracted firm capacity. NMPC also has a contract with the project to provide firm wheeling of power to Con Edison. Our analysis considers only the project's purchase power agreement with Con Edison. Commercial operation began in November 1994, although we model it assuming a 1995 commercial operation date. We use the contract as amended on December 9, 1992.

Dispatchability

The project is a Qualifying Facility (QF) under PURPA. When establishing pricing and dispatch rules, the contract defines three operating periods. Period 1 includes years one through five (1995-1999); Period 2 includes years six through twenty (2000-2014); Period 3 includes years twenty-one to forty (2015-2034). The buyer is allowed only limited economic curtailment. The buyer is allowed 250 hours of curtailment in 1994 and 1995, and 400 hours per year for the remainder of Periods 1 and 2. In Period 3, annual curtailment is reduced to 200 hours. The buyer can curtail the seller no more than 54 times per year. The buyer also is excused from its purchase obligations under certain noneconomic conditions, including inability to accept power due to interconnection problems.

Pricing

This project is different from many in the sample. Pricing in the contract is written in terms of avoided costs to the buyer, Con Edison, which makes the contract appear to be more “standard offer” like than one acquired through competition. The purchased power agreement's current form, however, was the subject of renegotiation, making the project subject to at least some competitive pressures. This contract is also unique in that it is still subject to NY PSC determinations regarding the proper method for computing avoided costs.

In this sense, the project developer is taking on some regulatory risk in addition to fuel price risk. Pricing changes substantially in three contract periods. A notable feature of this project is that, because the capacity charge is small, the assumed capacity factor does not make a difference on levelized price. Further, a relatively large portion of the project's revenues are indexed to Con Edison's avoided costs, which we index to natural gas and coal prices. Thus, the project is sensitive to fuel price assumptions and the time horizon chosen for levelization. For example, a 40-year (the contract term) time horizon results in a levelized price 12 percent higher than a 20-year levelized price.

Capacity

Although the contract is for firm power, there is no capacity charge in Period 1. A supplemental energy charge (see energy pricing section, below) appears to compensate for the absense of a capacity charge in Period 1. The capacity charge in Period 2 is $81/kW-yr. The capacity charge drops in half (to $40) during Period 3, producing a 20-year levelized payment of $43 per kW-year.

Energy

Energy prices are a function of the buyer's marginal energy costs (MECs). In Period 1, price is set at MEC plus a supplemental energy charge of $0.026/kWh. In Periods 2 and 3, price is set at 93.7% and 88.75% of MEC, respectively. The contract specifies that the MEC will be set to the then current, PSC-approved, short-run energy-only avoided costs. The most recent NY PSC long-run avoided cost (LRAC) decision is used as the basis for forecasting MECs in the future. LRACs are taken from NYPSC Order dated 24 Nov 93 in Case 93-E-0175. These avoided energy costs are taken from the energy-only LRAC (transmission level) column of Table 3 of Appendix D. For the first 10 years of the contract, IERs were estimated by taking the most recent LRACs and normalizing them to the most recent gas and coal (using 75%/25% weights) prices forecasted by the NY PSC.[26] For the last 30 years of the contract, an IER of 10,240 Btu/kWh is used, which is equal to the average IER of the first 10 years of the contract. This IER is multiplied by our weighted average coal-gas price forecast to compute a MEC for each year. The first-year weighted average coal-gas price indicated in the NY PSC Order ($2.67/MMBtu) is used as it is a estimate of current delivered gas prices in New York for use by Con Edison. Gas prices are escalated at the gas "combined" index, similar to other gas fired projects modeled in this study. Coal prices escalate at inflation.

O&M

Separate O&M charges apply in Period 2. First-of-period value is $0.010/kWh for Period 2. This value escalates at inflation. In Period 3, the O&M charge is reduced by 50 percent. We estimate that its value at the beginning of Period 3 will be $0.009/kWh.

[26] The NY PSC's LRACs are not used directly because their fuel price escalation rates may differ from ours.

A.5 Panda (G19)

Parties

Virginia Electric Power Company (Virginia Power) and Panda-Rosemary, L.P.

Facility Description

The Panda plant is a QF cogeneration facility constructed in the service territory of North Carolina Power, a subsidiary of Virginia Power. The contract indicated an expected nameplate and summer dependable capacity of 172 and 145 MW, respectively. The project is now in operation and Virginia Power reports the actual summer net dependable capacity, which is also the contract capacity, to be 165 MW. Actual net dependable winter capacity equals 198 MW. Panda is capable of running on gas and oil, and the contract pricing reflects the use of both fuels. However, we assume the project runs 100 percent of the time on gas.

Dispatchability

Virginia Power has the right to fully dispatch the plant subject to “design limits.” Design limits will allow the facility to be operated at 0 percent and between 20-24 percent, 55-65 percent, and 80-100 percent of the plant's dependable capacity.

Pricing

Capacity
The capacity price begins at $160 per kW-year (nominal 1991 dollars) and is gradually reduced to $100 per kW-year by the sixteenth year, producing a 20-year levelized price of $160 per kW-year (1994 dollars).

Energy
Panda's commercial operation date was in late 1990, but a significant revision to the contract's energy price became effective July 30, 1993 (1993 energy price revision). We model the contract under the original pricing for the first two full years and switch to the revised pricing from the 1993 contract year onward.

For 1991 and 1992, the energy price equals a base value of 2.798 cents per kWh escalating with fuel prices. The escalation rate equals the ratio of current gas prices (Composite Gas Index, CGI) to October 1986 gas prices (Base Gas Index, BGI). Both the Base and Composite indices are calculated by taking the weighted average of prices paid for natural gas by electric utilities (25 percent), spot No. 6 fuel oil prices (F.O.B. New York) and natural gas prices in the spot market (50 percent). We use natural gas spot prices and natural gas prices as delivered to electric utilities from Natural Gas Monthly to develop a proxy BGI and CGI.

For 1993, the contract continues to base pricing on a composite index, but the index focuses more on spot natural gas and includes explicit indices for gas transportation costs. We again estimated an index value using gas prices from Natural Gas Monthly and from exemplary transportation prices shown in the contract amendment. Beginning in 1994, energy prices are escalated using our “Combined” gas index.

The 1993 energy price revision also contained provisions wherein under certain conditions, the buyer could buy gas for the project. Under this operating regime, the seller would only get a management fee and be reimbursed for some out-of-pocket transportation costs. This revision is novel in that it further integrates the operation of the plant into the buyer’s system; under certain conditions the buyer is not only dispatching the plant, but is buying and nominating fuel for the plant. Although this aspect of the revision is interesting, we assume for purposes of computing prices that the project is always subject to the traditional pricing provisions of the 1993 energy price revision.

A.6 SJE (G20)

Parties

Virginia Electric Power Company and SJE Cogeneration Company, Inc.

Facility Description

The SJE plant operates on natural gas and has an estimated dependable capacity of 229 MW in summer and 264 MW in winter. Oil is used as backup fuel, but our analysis assumes 100 percent gas operation.

Dispatchability

Virginia Power has the right to fully dispatch the plant subject to “design limits.” Design limits will allow the facility to be operated between 99 MW and 116 MW or between 197 MW and the maximum peak load capacity. Virginia Power can also shut the plant down. The peak load capacity of the facility is 247 MW at 59° F. In addition, the seller must maintain a dependable capacity of at least 229 MW between June 15 and September 15.

Pricing

Capacity
The capacity price is set at $134 per kW-year for the first fifteen years of the project and reduces to $77 per kW-year for the final ten years of operation. This produces a twenty-year levelized value of $141 per kW-year (1994 dollars). If the facility's dependable capacity is less than 85 percent of the original estimated dependable capacity, the seller must pay liquidated damages of $21.29 per kW for the difference between 85 percent of estimated dependable capacity and actual dependable capacity. These liquidated damages escalate with inflation. Our analysis does not reflect the possibility of liquidated damages.

Energy
The energy price equals a base value of 2.287 cents per kWh escalating with fuel prices. The escalation rate equals the ratio of current gas prices (Reference Gas Index) to October 1986 gas prices (Base Gas Index). Both the Base and Reference indices are calculated by taking the weighted average of prices paid by pipeline companies (25 percent), electric utilities (25 percent), and spot prices (50 percent). Using Natural Gas Monthly data[27] we estimated

[27] The contract stipulates that interstate pipeline and electric utility prices should be obtained from Natural Gas Monthly, and spot prices should be obtained from Natural Gas Week and Natural Gas Intelligence. We used Natural Gas Monthly values for all indices.

energy prices for 1991-1993. Beginning in 1994, energy prices are escalated using our "Combined" gas index.

A.7 Hopewell (G21)

Parties

Virginia Electric Power Company and Hopewell Cogeneration, Inc.

Facility Description

The Hopewell plant is a QF fueled by natural gas with an estimated dependable capacity of 306 MW in summer and 364 MW in winter. Oil is used as the backup fuel, but our analysis assumes 100 percent gas operation.

Dispatchability

Virginia Power has the right to full economic dispatch subject to “design limits.” This is defined as the range of operation of the facility above 68 MW. Virginia Power has the ability to start and shut down the plant. In addition, the seller must maintain a dependable capacity of at least 248 MW between June 15 and September 15.

Pricing

Capacity
The capacity price has two components. The first is fixed at $11.975 per kW-month for the first fifteen years and $6.433 per kW-month for the next ten years. The second equals $4.9229 (as of April 1, 1989) per kW-month and escalates annually with inflation. The ultimate capacity price equals a weighted sum of the two prices, with the fixed component receiving a weight of 84.15 percent and the escalating component receiving a weight of 15.85 percent. This produces a 20-year levelized capacity payment of $150 per kW-year (1994 dollars).

If Hopewell's dependable capacity falls below 85 percent of original estimated dependable capacity, then the seller must pay liquidated damages of $3.35 per kW-month (1986 $s) for the difference between 85 percent of estimated dependable capacity and actual dependable capacity. These liquidated damages escalate with inflation. Our analysis does not reflect the possibility of liquidated damages.

Energy
The energy price also has two components. The first is a fixed operations and maintenance charge of 0.213 cents per kWh. The second is a fuel charge which equals a base value of 2.287 cents per kWh escalating with fuel prices. The escalation rate equals the ratio of current gas prices (Reference Gas Index) to October 1986 gas prices (Base Gas Index). The Base Gas Index equals the average of gas prices paid by major pipeline companies and electric utilities. The Reference Gas Index equals the weighted average of prices paid by

pipeline companies (25 percent), electric utilities (25 percent), and spot prices (50 percent). We estimated energy prices for 1990-1993 using fuel prices reported in Natural Gas Monthly.[28] Beginning in 1994, energy prices are escalated using our "Combined" gas index. If actual fuel costs differ from fuel costs calculated using the Reference Gas Index by 10 percent or more over a twelve month period, then the energy price will be retroactively adjusted.

[28] Electric utility and pipeline prices should be obtained from Natural Gas Monthly, and spot prices for the Louisiana Gulf Coast Offshore should be obtained from Natural Gas Week and Natural Gas Intelligence. To simplify the analysis, we used Natural Gas Monthly values for all prices.

A.8 North Las Vegas (G22)

Parties

Nevada Electric Power and Las Vegas Cogeneration, LP

Facility Description

The North Las Vegas plant is a 45 MW cogeneration QF fueled by natural gas.

Dispatchability

During peak hours, the entire facility will be dedicated to Nevada Electric Power (NEP). During off-peak hours, the utility will have the right of first refusal to purchase the entire capacity and energy output. The contract also states that NEP may curtail the project at any time (pp. C-5). The parties estimate that annual energy delivery will equal 208,000 MWh, or an average of 53 percent capacity factor.

Pricing

The pricing for this contract is unique, reflecting Nevada Electric Power's high demand for peak power. Separate pricing schedules apply for “Summer On-Peak,” “Winter On-Peak,” and “Off-Peak” hours. The “Summer On-Peak” price has a capacity component of 4.781 cents per kWh and an energy component of 2.273 cents per kWh. The “Summer On-Peak” period includes the months of May through September between the hours of 10:00 am and 10:00 pm each day. Similarly, the “Winter On-Peak” price has a capacity component of 2.282 cents per kWh and an energy component of 2.273 cents per kWh. The “Winter On-Peak” period includes the months of October through April between the hours of 5:00 am to 10:00 am and 4:00 pm to midnight each day. During off-peak times, the price consists only of an energy payment of 1.986 cents per kWh. The above prices are April 30, 1992 values. These values will be escalated annually by 80 percent of the changes in the Consumer Price Index for all Urban Consumers. We use our “Inflation Index” as a proxy for the urban CPI.

The average annual price equals the average of the price for each period (Summer Peak, Winter Peak, Off-Peak) weighted by the hours of operation for each period. The distribution of annual hours to the different categories will have a significant effect on the average annual price. There are several provisions in the contract that provide insight into determining how to allocate the operating hours to the various time slots. First, Nevada Electric Power places great importance on the availability of peak power. This is evidenced by the high price offered for this energy as well as the stipulation that the facility must deliver at least 90 percent capacity factor during peak times. Accordingly, as the capacity factor decreases from 100 percent, the on-peak capacity factor declines at one-fifth the rate of off-peak, with a minimum of 90 percent on-peak. Thus, with an overall capacity factor of 90 percent, the on-peak capacity factor would be 98 percent (100 percent minus one-fifth of 10 percent). If the average annual capacity factor falls below 47 percent, then off-peak operating hours would be zero and the on-peak capacity factor would fall below 90 percent. In these circumstances, Nevada Electric Power would still have to pay for the minimum of 90 percent capacity factor for on-peak.

This contract has two unique provisions concerning fuel price risk and commercial operation date timing. First, the energy price is indexed to inflation rather than fuel prices. Thus, the seller bears the risk of differences between inflation gas escalation rates. Second, if the seller does not achieve firm operation by June 1, 1994, the seller must reimburse Nevada Electric Power for the difference between replacement power cost and contract prices, provided replacement power is more expensive.

A.9 Blue Mountain (G23)

Parties

Metropolitan Edison Company and Blue Mountain Power, LP

Facility Description

The Blue Mountain project with a net generator nameplate capacity of 205 MW of which Metropolitan Edison intends to purchase 150 MW of capacity and associated energy. The facility is located in Richland, Pennsylvania and has been classified by FERC as an Exempt Wholesale Generator as defined under PUCHA. The facility will operate entirely on gas. Commercial operation is expected by July 1997.

Dispatchability

The facility is fully dispatchable.

Pricing

Capacity
The capacity payment consists of capacity and O&M components. A schedule of capacity payments is provided in the contract. The O&M payment equals $81 per kW-year as of 1997 and escalates at 85 percent of inflation. The O&M value is then multiplied by an availability factor, which we have assumed is 1. Thus, the 20-year levelized annual capacity payment equals $338 ($247 Capacity plus $92 O&M, in 1994 dollars).

Energy
The energy payment consists of energy and fuel transport payments, which are priced per kWh, and a spinning payment, which is priced per hour of operation. The energy price equals 1.05 cents per kWh in 1997 and escalates at 5 percent annually until 2011 and 9 percent annually thereafter. The fuel transport payment equals 0.02 cents per kWh in 1997 and escalates with inflation. The spinning payment is designed to cover variable transportation, variable O&M, and fuel commodity payments that must be made in order to operate the facility. We converted these payments from a per hour to a per kWh basis by assuming that the facility operates at full capacity during those hours that it runs. While this may decrease the price per kWh (by amortizing the spinning payment over too many kWh's), the effect will be small since the spinning payment is typically less than 10 percent of total price per kWh.

Start Payments
The seller shall be paid for cold and hot starts of the facility. Such payments are excluded from our analysis. The cold start payment is comprised of maintenance ($3,756 per start),

fuel commodity ($1,225 per start), and fuel oil components ($1,943 per start). The hot start payments also are comprised of maintenance ($3,575 per start), fuel commodity ($734 per start), and fuel oil ($1,099 per start) components. All values are expressed in 1991 dollars and escalate annually.

Payments from Seller to Buyer
If the facility is unable to achieve the contract capacity of 150 MW by the commercial operation date, then the seller must pay Metropolitan Edison for liquidated damages. This is a one-time payment that equals $305,000 * (150 MW - available MW). The possibility of such a payment is not reflected in our analysis.

The seller must achieve a target performance level of 95 percent capacity factor during peak hours. If such a level is not achieved, the seller must pay Metropolitan Edison a stipulated fee for each MWh of energy unable to be delivered. These payments equal $30.41 per MWh in 1990 and escalate at 6 percent per year. These payments are not reflected in our analysis.

A.10 Enron (G24)

Parties

New England Power and Enron

Facility Description

The facility will consist of a 140 MW natural gas-fired combined cycle generator. The facility will be fueled with 365-day, firm natural gas supplied from Distrigas' liquefied natural gas facility. No producer contracts or export approvals are needed to secure Canadian supply to the facility. Commercial operation commenced in July 1993. Enron expects this facility to be competitive with all new base load power plants in New England. The agreement runs for a primary term of 20 years, but is subject to New England Power's (NEP) right of termination anytime after the 15th anniversary. Our understanding is that the FERC-filed contract is no longer operative and is subject to litigation. We could not obtain the latest contract, and so we rely on the one filed at FERC.

Dispatchability

NEP has agreed to purchase 58 percent of the facility's net electric output, subject to NEP's right of economic dispatch. NEP also has the right to increase its entitlement from the facility.

Pricing

Capacity

- The non-fuel charge includes O&M expenses, depreciation allowances, interest charges on project debt, taxes, and return on investment. This component escalates at 5 percent per year, provided the unit was available to produce energy for sale 90 percent of the time. The 1993 price equals $207/kW-year, producing a 20-year levelized price of $308/kW-year.
- The fixed gas charge covers payments made under Enron's gas purchase agreement. This charge escalates with filed transportation rates of four pipelines that provide transportation from Alberta to Boston. We use our gas “Transport” index as a proxy. The 1993 value equals $116/kW-year, producing a 20-year levelized price of $171/kW-year.
- The gas transport charge is designed to cover the cost of transporting gas from the supplier's terminal to the facility. This charge will escalate with the filed rate for Boston Gas' Quasi-Firm Transportation Rate. We used our Gas “Transport” Index as a proxy. The 1993 value for this charge equals $29/kW-year, producing a 20-year levelized price of $41/kW-year.

Energy

- The kWh charge is applied to each kWh of energy supplied to NEP. The initial value for December 1988 is $0.0119/kWh. This charge escalates with the "Weighted New England Power Pool Fossil Energy Cost." We used a 75/25 percent weighted average of our natural gas and coal escalation rates as a proxy.
- After the fifth and tenth years of operation, the energy charge can be changed to the lesser of a charge which reflects a cost of gas comparable to the cost of gas delivered to NEP's electric generating facilities, or a charge which would have allowed the unit to be dispatched at an 80 percent capacity factor.

A.11 Tiger Bay (G25)

Parties

Destec Energy and Florida Power Corporation

Facility Description

Tiger Bay is the consolidation of 5 QF contracts between Florida Power and various developers. The following lists the QF projects that are a part of Tiger Bay:

Table A-10. List of Individual Tiger Bay Contracts

Contract Name	Size (MW)	Pricing	Commercial Operation Date
General Peat Unit #1	57	Described below	January 1995
General Peat Unit #2	57	Same as Unit #1	January 1995
General Peat Unit #3	57	Same as Unit #1	January 1995
Timber	6	Same as Unit #1	January 1995
Eco Peat	40	Described below	June 1995

According to staff at the Florida PSC, the pricing of General Peat Units #2 and #3 were "slightly different" than that for Unit #1. The exact differences have not been confirmed, and our analysis assumes that they are the same.

Note that these capacities are higher than what is shown in the contracts. According to a representative from Florida Power, the developers can actually produce and be paid for up to 110 percent of the contract capacities, and this is what the developers are planning to produce.

Dispatchability

The facilities are QFs under PURPA and because the purchased power contracts do not state otherwise, these QF facilities are technically not dispatchable. That is, the entire energy of the project must be purchased by the buyer at the stated price. Our understanding is, however, that a limited amount of dispatchability has been negotiated between the buyer and seller without a modification to the contracts. The buyer may reduce project output to 80 percent in off peak hours. Further the buyer is allowed to schedule up to three, two-week outages during its resource "rich" seasons, the fall and spring.

Because this project represents the combination of several QF contracts with different pricing terms, it is unclear which contract the seller should bill through first. According to Florida Power, the individual contracts will be "dispatched" prorata to the contract capacities. For example, if the capacity factor in a month is 90 percent, revenues under each contract will be computed assuming a 90 percent capacity factor.

Pricing General Peat and Timber

Term
These contracts have a term of 30 years, beginning in 1995 and ending in 2024.

Capacity
The contract specifies a stream of capacity payments, starting at $192/kW-year in 1995 and increasing to $1,148/kW-year by 2024. These payments have a 20-year levelized value of $293/kW-year (1994 dollars).

Energy
Energy price is to be the lesser of the "1995 statewide avoided unit" or Florida Power's actual avoided costs. According to Florida Power, a reasonable simplification is to assume that the avoided unit will determine on-peak prices and system avoided costs will determine off-peak prices. That is, system avoided costs are higher than the avoided unit costs in the peak period. The following is a simplified energy payment formula:

$$Energy\ Price\ =\ \frac{11}{24}\cdot coal\ price\ \cdot\ heat\ rate\ +\ \frac{13}{24}\cdot off\text{-}peak\ energy\ price$$

where

- 11/24, 13/24 represent on- and off-peak time fractions, respectively.
- Coal price is the average price of coal for Big Bend Unit #4, a Tampa Electric Company unit designated as the 1995 the statewide avoided unit. We assumed that base year prices for the avoided coal plant are based on a recent 3-year average of actual coal fuel costs (1991 to 1993).
- Heat rate equals 0.009790 MMBtu/kWh.
- Off-peak energy price equals Florida Power's system off-peak energy price. We use a company provided forecast of system off-peak avoided costs through year 2002. After that time the off peak price is assumed to escalate at the coal escalation rate.

Pricing: Eco Peat

Term
The Eco Peat contract has a term of 30 years, beginning in 1996 and ending in 2025.

Capacity
The developer has chosen a capacity payment option that capitalizes 20 percent of the expected energy payments. Under this option, a specific stream of capacity payments is given in the contract, starting at $251/kW-year in 1996 and increasing to $1,062/kW-year in 2025. This produces a 20-year levelized payment of $333/kW-year (1994 dollars).

Energy

The following is the variable energy price (VEP) formula for Eco Peat:

$$\textit{Energy Price} = 0.8 \cdot (0.85 \cdot \textit{coal price} \cdot \textit{heat rate} + 0.15 \cdot \textit{off-peak energy price})$$

where:

- 0.85 and 0.15 represent proportion of time that the energy price is pegged to the Crystal River plant and Florida Power system avoided costs, respectively. Florida Power's Crystal River plant is a baseload plant that is likely to operate about 85% of the time according to Florida Power.
- Coal price represents the average price of coal for Crystal River Units #1 and #2. As with the Big Bend coal prices, we use recent historical coal prices to determine base year prices and escalate prices in the future at our assumed coal escalation rate.
- The heat rate equals 0.009830 MMBtu/kWh.
- Off-peak energy price equals Florida Power's system off-peak energy price. We use a company provided forecast of system off-peak avoided costs through year 2002. After that time the off peak price is assumed to escalate at the coal escalation rate.
- Energy payments are multiplied by 0.8 because the developer is taking a higher capacity payment. See description, *capacity,* above.

A.12 Hermiston (G26)

Parties

Pacificorp and Hermiston Generating Company, LP

Facility Description

The Hermiston facility will be a multi-unit, natural gas-fired combined cycle generating plant. Distillate oil or propane will be the secondary fuel. The natural gas will be purchased from western Canadian production fields and transported through several pipeline systems to the generating facility.

The facility has a bus bar rating of 474 MW with a minimum average summer rate of 407 MW and an expected reliable output of 469 MW under normal operating conditions. The facility is located within the service territory of an electric cooperative. Output is delivered to the cooperative, which will deliver it to Bonneville Power, which will deliver it to Pacificorp. Provided the facility is able to meet 100 percent of its power sale obligations, Hermiston will sell steam to Lamb-Weston, Inc. Commercial operation is expected to commence in September 1996.

Dispatchability

The facility is dispatchable within the following constraints:

- Pacificorp may elect to schedule no generation from one or both generating units or may schedule between 25 percent and 100 percent of the facility's minimum availability obligation.
- Pacificorp may not submit a schedule that requires any one generating unit to be operated at less than 50 percent of capacity.
- If Pacificorp schedules less than 100 percent of the facility's capacity, it shall specify how the individual generating units should be dispatched.

Pricing

Capacity

All initial capacity charges are expressed as a total payment times the ratio of actual capacity provided divided by minimum capacity. Our analysis assumes that actual capacity and minimum capacity are the same. Thus, the annual capacity charges simply reflect the total annual payment stipulated in the contract divided by minimum capacity (407 MW).

- During the first twenty years the demand charge equals $4,441,992 per month, producing a price of $131 per kW-year. After the twentieth year the demand charge is reduced to $79 per kW-year.

- During the first twenty years the O&M charge equals $667,000 per month (as of 11/93) and escalates at 4.5 percent per year. This produces a price of $22 per kW-year in 1996 and $51 per kW-year in 2015. After twentieth year, the price calculation methodology is nearly identical.
- During the first twenty years the transport charge equals $1,164,000 per month, producing a price of $34 per kW-year. After year twenty, the transportation price should equal actual charges incurred by the seller. We assumed that these charges are the same as during the first twenty years.

Energy

- The base energy price equals $0.012 per kWh as of 11/93. This escalates at 5.5 percent per year for the first fifteen years. In years 16 to 30, the energy price is based on actual fuel expenditures. To make this contract consistent with others, we escalated the original price of $0.12 per kWh using our Gas “Combined” Index for calculating the energy price in years 16 to 30.
- The O&M energy price equals $0.0003 per kWh as of 11/93. This escalates at 4.5 percent per year. After year twenty, actual costs are used. To estimate these actual costs, we used the same methodology as was used to calculate the price during the first twenty years.
- The transport energy price equals $0.0004 per kWh. This price is fixed for the first twenty years. After year twenty, actual costs are used. We used the value from the first twenty years as a proxy.

A.13 Tenaska (G28)

Parties

Bonneville Power Administration and Tenaska Washington Partners II, LP

Facility Description

The facility will consist of a single-train, combined-cycle combustion turbine with a net electrical generating capacity of 248 MW. The project will be operated with natural gas as the primary fuel and No. 2 fuel oil as the secondary fuel. Natural gas will be delivered by the Northwest Pipeline Corporation. Commercial operation is expected to commence in July 1996.

Dispatchability

The contract delineates rules for dispatching the facility on a monthly basis.

- On a monthly basis, Bonneville Power must either (1) accept the facility's entire output or (2) displace (not accept) the facility's entire output. One pricing schedule applies for the first two months of displacement; a second pricing schedule applies for additional months displaced. We generally translate a given capacity factor into an equivalent number of displaced months.
- If Bonneville Power wishes to displace either (1) a portion of the facility's output or (2) a portion of a month, it shall be on terms and conditions agreed to by Tenaska.

Pricing

Tenaska has a unique way of characterizing its price. Most contracts contain a fixed capacity payment, which the seller receives regardless of how much the facility is dispatched, and a variable energy payment which is a function of dispatch. The Tenaska contract has three different pricing schedules: (1) delivered energy, (2) the first two months of displaced energy, and (3) additional months of displaced energy.

- A twenty year pricing schedule is provided in the contract for delivered energy. This schedule has been slightly adjusted as a result of changes in interest rates and non-gas costs between the time the contract was originally signed (4/1/94) and the deadline for contract appeals (6/29/94). This produces a twenty-year levelized price (assuming no displacement) of 5.25 cents per kWh. With prices set for twenty years, the seller bears the fuel price risk.
- During the first two months of displacement each year, the above per kWh price is adjusted in three ways to form a displacement price. First, the price is reduced using a schedule included in the contract (Fixed Displacement Price). Second, the price is reduced to capture Northwest Pipeline's firm commodity rate, GRI charges, and small FERC charges (see Table 1). Third, the price is reduced to account for foregone fuel

losses. These adjustments change the displacement price from 5.25 cents per kWh to 2.91 cents per kWh. Because the displacement energy is priced less than the full price, average price rises as capacity factor falls.

- A third pricing schedule applies to additional months of displacement. It is the same as the displacement price described above, except the Fixed Displacement Price is replaced with foregone spot fuel costs, net of contract liquidation fees. Contract liquidation fees change based on the number of months displaced. With six months of total displacement, the price for the final four months of displaced energy equals 3.1 cents per kWh.

Table A-13. Current Tariffed Prices for Gas Transportation on the Northwest Pipeline System

Reservation Charges (includes the reservation charge component of the GRI surcharge)	
($/month per Mcf/day of reserved capacity)	
High Load Factor	8.0889
Low Load Factor	8.0129
Volumetric or Commodity Rates	
($ per Mcf)	
Commodity Rate	0.0011
GRI surcharge	0.0085
ACA surcharge and coal (using 75%/25% weights)	0.0025
Total	0.0121
Fuel Use	
Fuel Use (% taken in kind)	1.09%
Fuel Use ($/MMBtu at $2.11/MMBtu)	0.0230
Current Tariffed Rates	
Source: Lyle Millham, NW Pipeline, 6/2/1994	

To calculate an average annual price per kWh, we simply take a weighted average of the three pricing schemes. For example, a capacity factor of 50 percent would be equivalent to six months of displaced energy; the average price equals (6/12) * fixed energy price + (2/12)

* 2-month displacement price + (4/12) * >2-month displacement price. We ignored the one-month block dispatch constraint for this analysis.

A.14 Commonwealth Atlantic (P02)

Parties

Virginia Electric Power Company and Commonwealth Atlantic, LP

Facility Description

The Commonwealth Atlantic plant has an estimated dependable capacity of 312 MW in summer and 371 MW in winter. The facility is comprised of three combustion turbine generating units which will be fueled by natural gas in the summer and No. 2 fuel oil in the winter.

Dispatchability

The facility is subject to economic dispatch, which allows Virginia Power to request as much power as is economic for its system, subject to facility design limits. These limits include:

- Each combustion turbine generating unit is capable of operating over the range of 75 percent to 100 percent of maximum output levels.
- The total facility is capable of operation over the range of 25 percent through 100 percent of dependable capacity, except that the facility is not capable of operation in the ranges of 33 percent through 50 percent and 67 percent through 75 percent of dependable capacity. The facility may also be shut down at Virginia Power's discretion. (These constraints are not modeled in our spreadsheet.)
- Operation of each combustion turbine shall not exceed ten hours per day.
- During the first two years following the commercial operation date, total facility operation shall not exceed 500 hours per year (<6 percent capacity factor).
- After the second year total facility operation shall not exceed 1,000 hours per year (<12 percent capacity factor).

Pricing

The Commonwealth Atlantic contract has separate pricing schedules for summer and winter months. The summer period includes the months of April through September; the winter period includes the months of October through March. We assume that the plant operates at the same capacity factor in summer and winter months. Accordingly, since there are six months in each period we simply average summer and winter prices to obtain an annual value. This produces a 20-year levelized energy price of 5.2 cents per kWh.

Capacity

- The fixed capacity payment is pegged to the interest rate of a 13-year treasury bond around the commercial operation date. The rate is linearly extrapolated from the rates of 10-year and 30-year bonds. Once the rate has been established, the corresponding payment, which is determined from a table provided in the contract, is fixed for the life of the contract. We estimated the 13-year treasury rate as 7 percent, which produces summer payments of $4.819 per kW/month and winter payments of $3.720 per kW-month or $51 per kW-year.
- The O&M capacity payment is also divided into summer and winter prices. The summer value equals $0.686 per kW-month and the winter value equals $0.5295 per kW-month (1988 $s). These values escalate with inflation, producing a 20-year levelized annual payment of $12 per kW-year.

Energy

Like other Virginia Power contracts, the energy price is calculated as follows

$$Energy\ Price = Base\ Price \cdot \frac{Reference\ Fuel\ Index}{Base\ Fuel\ Index}$$

where the base price and the methodology for calculating the fuel indices are stipulated in the contract. Unlike other Virginia Power contracts, summer energy prices are pegged to the price of natural gas, while winter energy prices are pegged to the price of No. 2 fuel oil.

The base summer price equals 2.19 cents per kWh. The base gas index equals the weighted average of spot and electric utility prices for the months of July, August, and September 1987, with the spot price receiving twice the weight of the electric utility price. The reference gas index is calculated in the same manner.[29] We calculated summer energy prices for 1987 (contract base year) and 1992 and 1993 (historical years that the plant has been operating) using the above formula. For 1994 and subsequent years, we calculated summer energy prices by escalating 1993 prices with our Combined Gas Index.

The base winter price equals 4.94 cents per kWh. The base oil index equals the average of US Gulf Coast Spot Pipeline No. 2 Oil for the months of October, November, and December 1987.[30] The reference oil index uses the same source. We used actual data to calculate the winter energy price for 1992. Beginning in 1993, we calculated winter energy prices by escalating the 1992 price by inflation.

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29 For both indices, spot prices should come from Natural Gas Week and Natural Gas Clearinghouse, and electric utility prices should come from Natural Gas Monthly. To simplify our analysis, we used Natural Gas Monthly for all prices.

30 Both indices should us prices reported in Platt's Oilgram Price Report. We substituted annual average No. 2 Fuel Oil prices as reported in Annual Energy Review.

A.15 Hartwell (P03)

Parties

Oglethorpe Power Corporation and Hartwell Energy, LP

Facility Description

The facility is located near Hartwell Dam in Georgia. It consists of two nominal 150 MW fossil fuel-fired combustion turbine generating units. The primary fuel for these units will be natural gas. Commercial operation commenced on April 7, 1994.

Dispatchability

The facility is fully dispatchable by the buyer subject to the facility's minimum operating level, its design limits, and air quality permit. The facility is capable of operating over the continuous range between its minimum and maximum operating level. These levels are delineated in the contract and vary with temperature. With an ambient temperature of 60° F, each of the two units has minimum and maximum operating levels of 49 MW and 166 MW respectively. The air quality permit limits operation to 2500 hours/year per unit, or an annual capacity factor of 29 percent.

Pricing

Capacity

- The fixed component equals $12.97 per kW-year as of January 1, 1989. This value escalates at inflation until the commercial operation date, after which the value is fixed in nominal terms. This produces an annual payment of $15.86 per kW.
- The O&M component equals $9.49 per kW-year as of January 1, 1989. This value escalates with inflation throughout the life of the contract. This produces a 20-year levelized price of $16 per kW-year.
- The debt service component is pegged to the 15-year Treasury yield and is locked in on the commercial operation date. The 15-year Treasury yield equaled 7.59 percent on April 8, 1994 producing a fixed debt payment of $57.86 per kW per year.

Energy

The energy price is calculated based on the facility's heat rate and fuel costs. Fuel costs are based on an initial gas price based on buyer's actual as costs during April 1994 and includes Georgia state tax and variable transport costs. According to the buyer, the project has not acquired firm gas transportation capacity. After that year, it escalates at our regular gas "combined" index. The initial heat rate is set at 10,400 Btu per kWh. This produces a 20-year levelized price of 3.8 cents per kWh.

A.16 US Windpower (W03)

Parties

New England Power and US Windpower

Facility Description

US Windpower will construct, own, operate, and maintain a wind turbine power generation project located on approximately 150,000 acres in Franklin and Somerset Counties, Maine. Electricity will be generated using USW Model 33M-VS wind turbines, each with a net nameplate rating of 300 kW. New England Power will ultimately purchase 20 MW of capacity under this contract. Of this 20 MW, at least 10 MW will come on-line by 1997 (Phase I), 2.5 MW by 1998 (Phase II), and 7.5 MW by 1999 (Phase III).

New England Power will have the right to claim all emission offset, allowance, or credit attributable to its portion of the wind generating facility. We have been informed that US Windpower is experiencing difficulties siting this project. The Maine agency in charge of siting has indicated that it may authorize only a 5 or 10 MW pilot project to assess possible impacts on wildlife.

Dispatchability

New England Power will purchase electricity from the facility on an as-available basis. The facility is expected to operate approximately 3,200 hours per year, which is equivalent to a 36.5 percent capacity factor.

Pricing

Unlike other contracts in our sample, which have fixed and variable prices, this contract is comprised of only an energy price. Each increment of capacity (Phase I, Phase II, and Phase III) has its own energy price. We calculated a base energy price for each year by taking an average of the three prices, weighted by the capacity associated with each price. This base price is then adjusted depending upon whether the energy is delivered on- or off-peak. For on-peak energy the annual base price per kWh is multiplied by 1.135; for off-peak energy the annual base price per kWh is multiplied by 0.885. The contract stipulates that the on-peak multiplier times the proportion of on-peak hours plus the off-peak multiplier times the proportion of off-peak hours must sum to 1.0. This implies that 46 percent of the hours are on-peak, and 54 percent of the hours are off-peak. To determine the average annual price per kWh, we calculated total revenue and divided by total sales. Thus, the average annual price does not vary with capacity factor, rather it is a function of the breakdown between on- and off-peak energy deliveries.

A.17 Comparison of Actual Recorded Prices to Our Estimates

Fifteen of the 26 projects in our contract sample should be operational by November 1994. (Table 2-1) Because of time lags in obtaining recorded data, and because the exact start dates of many of these projects are not known, an easy comparison can be made only for projects that were operational on or before January 1, 1993. Only seven sample contracts meet this criterion. Table A-3 compares recorded and estimated prices for six of these projects. Actual prices were supplied by the purchasing utilities. (Virginia Electric Power 1994). Estimated prices come from our sample data, with nominal 1993 prices adjusted to reflect actual capacity factors.

Table A-18. Reconciliation of Estimated and Actual Prices

1993 Recorded Data		Capacity Factor	Energy Price ($/kWh)	Capacity Price ($/kW-yr)	Total Avg. Price ($/kWh)
Buying Utility: VEPCO					
G20 - Richmond Power Enterprises (SJE)	Recorded	7%	0.0246	139	0.2636
	LBL	7%	0.0254	134	0.2446
	Percent Dev				-7%
G21 - Hopewell Cogeneration	Recorded	6%	0.0260	128	0.2946
	LBL	6%	0.0247	132	0.2755
	Percent Dev		-0.0509	0	-6%
G19 - Panda Energy	Recorded	2%	0.0303	179	0.9543
	LBL	2%	0.0294	160	0.9418
	Percent Dev				-1%
G07 - Doswell #1 & #2	Recorded	34%	0.0305	144	0.0792
	LBL	34%	0.0226	156	0.0751
	Percent Dev				-5%
P02 - Commonwealth Atlantic	Recorded	5%	0.0278	68	0.1921
	LBL	5%	0.0365	60	0.1738
	Percent Dev				-11%
Buying Utility: ConEd					
G10 - Linden	Recorded	65%	0.0482	138	0.0722
	LBL	65%	0.0479	138	0.0722
	Percent Dev				0%

Source: LBL, FERC Form 1s, VEPCo (1994)

Our estimated prices for 1993 compare reasonably well for the Virginia Power projects. Estimated prices for SJE (G20), Hopewell (G21), Panda (G19), and Doswell (G07) are all within 7% of actual prices. The Commonwealth Atlantic estimated price differs by 11% from actual prices. A large spread between summer and winter energy prices may contribute to this difference. The Commonwealth Atlantic project operated at only a 5% capacity factor in

1993. If we assume that all of these hours were in the winter, the discrepancy between estimated and actual prices becomes about 5%. If we assume that all of these hours were in the summer, the discrepancy becomes 17%. Deviations between energy and capacity prices for individual projects are greater than the deviations for total price. This probably stems from whether certain payments, such as pipeline transportation charges, are considered energy- or capacity-related. Another interesting aspect of the Virginia Power data is the actual capacity factors for each project for 1993. Doswell's capacity factor was 34%, and the three other nonpeaker facilities (Richmond, Hopewell, and Panda) had even lower capacity factors, less than or equal to 7%. These capacity factors are low considering that all of these projects were designed to operate as baseload or intermediate plants.

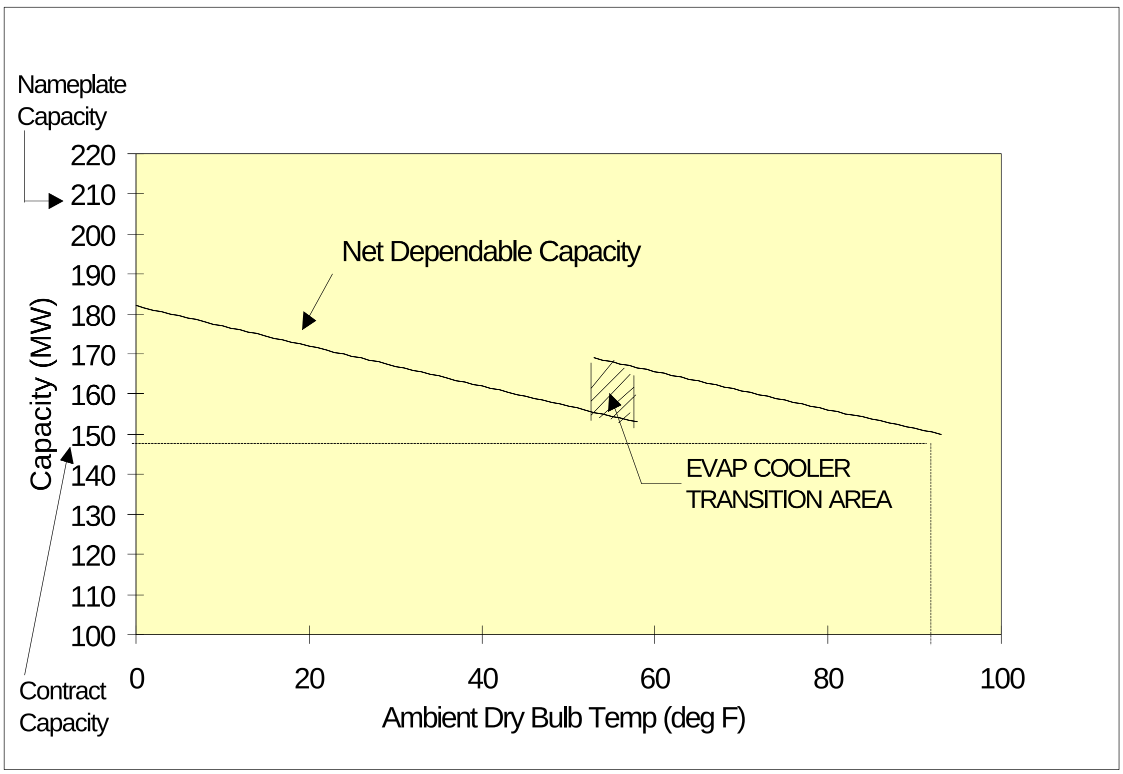
In the case of Con Edison's Linden contract, the apparent excellent match between recorded and estimated data is no accident. Because of a lack of specificity in the purchased power agreement regarding the price of electric energy, we relied on the 1993 recorded data to set the energy price in our price analysis.

Defining Capacity in a Purchased Power Agreement

B.1 Introduction

The term capacity takes on a variety of meanings in the electric industry. Several definitions have been standardized by industry organizations such as the North American Electric Reliability Council (1991, Appendix B). Capacity is a fundamental characteristic of all purchased power agreements analyzed in this report. A portion of project revenues typically are pegged to capacity, and a consistent measure of capacity across projects is needed to examine the relationship between capacity and price. This section presents several commonly used definitions of capacity and clarifies which measure of capacity we used in our analysis. These definitions are illustrated using an example for the Blue Mountain Power (BMP) project, one of the project contracts in our sample (Figure B-1).

Figure B-1. Plant Capacity versus Temperature for the Blue Mountain Power Project (G23)



B.2 Types of Capacity Defined

B.2.1 Nameplate Capacity

Nameplate capacity is the total capacity of all of a plant's turbine-generator units as rated by the manufacturer, without consideration of station service auxiliary power needs. For the BMP project, the nameplate capacity is 210 MW (Figure B-1).

B.2.2 Maximum and Dependable Capacity (Gross or Net)

Gross maximum capacity (GMC) is the gross capacity of the plant at standard temperature and pressure conditions. Gross dependable capacity (GDC) is the maximum capacity of the power plant adjusted for the temperature and pressure conditions of a particular season or design day. *Net* maximum and dependable capacities are respectively equal to GMC and GDC minus the capacity utilized for station service and auxiliary power needs. Power plants are generally less efficient when ambient temperatures are higher. This effect is more pronounced for gas turbines, which use ambient air as the working fluid, than for steam turbines. For the BMP combined cycle project, net dependable capacity is shown as the temperature-sensitive line in Figure B-1.[31] The figure shows that net dependable capacity drops 12% as the ambient temperature rises from 30 to 93 degrees F.

B.2.3 Contract Capacity

Most often, contract capacity is defined in terms of a project's net dependable capacity at the hottest expected coincident ambient temperature (design temperature) for the buying utility. In the case of the BMP project, the summer design temperature is 93 degrees F, and the resulting contract capacity is 150 MW. Contract capacity may also include adjustments for losses between the plant's busbar and the point of utility interconnection. These losses may be significant if the project is a considerable distance from its interconnection with the buying utility or if an intermediate utility is wheeling the power. Also, contract capacity will be less than a facility's net maximum or dependable capacity if some of the power is used at the site for industrial self-generation purposes or if some of the net dependable capacity is reserved for other buyers. Independence and Enron are examples of facilities whose contract capacities are considerably less than their net dependable capacities.

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[31] In Figure B-1, "evap. cooler transition area" indicates the region where ambient temperatures become high enough to allow for the operation of an evaporative cooler. Such a cooler improves (increases) the difference between the inlet and outlet temperatures of the working fluid and increases the capacity of the facility.

For our statistical analysis, we kept track of each project's total capacity (usually a facility's net maximum capacity) and its contract capacity. If contract capacity is differentiated by season, we used the summer value regardless of the peak season of the buying utility because our goal is compare projects under similar conditions. Other than this convention of using the same season, we made no attempt to normalize project capacities to a single climate.

B.2.4 Available Capacity (Gross or Net)

Although a project can be rated at a maximum or dependable capacity, its *available* capacity at any moment may be smaller because of full or partial maintenance outages, forced outages, deratings, or, in the case of intermittent resources, a shortage of the underlying fuel source (e.g., water or wind). Nearly all contracts base their capacity revenues on the product of a capacity price and a contract capacity, but require reductions in capacity payments if net available capacity is smaller than the contract capacity during peak hours or seasons. Most contracts define peak periods narrowly enough so that scheduled maintenance does not require a reduction in capacity payments. The seller is usually at risk, however, for unavailable capacity caused by full or partial *forced* outages. We did not attempt to predict availability on a project-specific basis, assuming that all the projects were fully available for purposes of estimating revenues and price.

Comparison of U.S. Prices with U.K. Prices

C.1 Introduction

This appendix compares our sample contract prices with those reported in another country that is pursuing a competitive generation market: the United Kingdom. We begin by presenting the available U.K. data. Next, we describe the steps taken to adjust the U.K. data to make it comparable with levelized prices from our sample. Finally, we illustrate that U.K. prices fall in the middle of the range of our U.S. contract sample prices.

C.2 The U.K. Data

The Office of Electricity Regulation (OFFER) in the U.K. has released two studies of the contract market in the electricity industry that has developed along side of the better-known Pool (OFFER, 1992, 1993). We focus attention on the contracts between the Regional Electricity Companies (RECs) and the Independent Power Producers (IPPs). All of the U.K. contracts are for combined cycle projects using natural gas. The OFFER report does not contain complete descriptions of U.K. contracts. Instead, it provides ranges of values. The stylized facts characterizing the RECs contracts with the IPPs are listed below. We reference the paragraph numbers (#) in OFFER (1992) as the source of these estimates.

C.2.1 Capacity Prices

(1) The fixed, or capacity, price revealed by OFFER is £75/kW-yr. This price is apparently an average or typical value for IPP-REC contracts. It is indexed to the Retail Price Index (RPI) or the Producer Price Index (PPI) for 15 years (# 95).

(2) There are variable costs in the capacity charge that are tied to "non-controllable" costs, such as "transmission charges and pooling and settlement costs." (# 89). We assume these are negligible.[32]

[32] The "pooling and settlement charges" are included in the uplift component of prices. These have typically been around 0.1p/kWh, although in particular months they have been as high as 0.3p/kWh (OFFER, 1993).

C.2.2 Energy Prices

(3) Unit energy prices are "between about 1.25p/kWh and 1.5p/kWh." These prices are indexed to movements in the prices of various fuels (# 94).

(4) Natural gas prices are based on British Gas tariffs. There are two main tariffs that were operative when the IPP projects were structured, LTI2 and LTI3. The price of gas under LTI2 was 17p/therm in 1992; for LTI3, the price was 21p/therm (# 133).

C.3 Comparison with U.S. Data

In this section we compare the U.K. contract prices with the U.S. project prices shown in Chapter 3. To compare the U.K. data to our levelized prices, we make several assumptions about exchange rates, inflation, discount rates, fuel costs, and levelization techniques. While this analysis may not be comprehensive, we have attempted to be explicit in our assumptions. Like our contract sample, the U.K. contracts provide for substantial dispatchability.

C.3.1 Assumptions

We use the same assumptions made elsewhere in this report regarding input parameters; specifically, inflation equals 4.1%, discount rate equals 9.8%, and gas combined index escalates at 4.8% per year. In addition, for purposes of converting currencies, we use \$1.75/£ as an average exchange rate over the period (second quarter of 1991 to second quarter of 1992) during which these contracts were negotiated (Council of Economic Advisers 1992, Table B-110).

C.3.2 Capacity Price

These prices need to be levelized over the fifteen year contract terms. Using standard calculations, a 15 year stream escalating at 4.1%/year is equivalent to a nominal levelized value that is 1.255 times the initial value at a 9.8% discount rate. This multiplier is usually referred to as a "levelization factor" in the engineering economics literature (Stoll, 1989). Combining the levelization factor appropriate to our assumptions and the capacity price, listed as Fact (1) in C.2.1, produces a capacity price of £94/kW. This is equal to \$165/kW, using our assumed exchange rate. This price is comparable to the U.S. data.

C.3.3 Energy Price

The energy price depends upon both fuel prices and conversion efficiencies. Using Facts (3) and (4) from C.2.2 we can calculate the conversion efficiencies if we assume that the low price quote in (3) (1.25p/kWh) corresponds to LTI2 (17p/therm) and the high price (1.5p/kWh) corresponds to LTI3 (21p/therm). For the low energy price and LTI2, the conversion efficiency is 7352 Btu/kWh (using "heat rate" units) . For the high energy price and LTI3, the conversion efficiency is 7142 Btu/kWh. These estimates are consistent with recent engineering estimates of the conversion efficiency of large scale gas-fired combined cycle projects in the U.S. (Beck 1993).

To levelize the energy prices so that they are comparable to U.S. contracts, a 20 year period is required. Assuming a fuel escalation rate of 4.8% and a discount rate of 9.8% per year produces a levelization factor of 1.333. This results in 20-year levelized energy prices of 1.76-2.11 p/kWh. This equals 3.07-3.69 cents/kWh, using our assumed exchange rate.

C.3.4 Total Price

Adding energy and capacity prices together for a comparison requires that we specify a capacity factor over which to spread the fixed capacity charges. It is convenient to use an 80% capacity factor so that U.K. prices can easily be compared to our U.S. sample prices in Table 3-1. We also should reconcile the 15 year levelization used for capacity prices with the 20 year horizon used for energy. To first approximation, however, we neglect the difference. This simplifying assumption is equivalent to assuming that the IPPs earn the equivalent of their 15 year capacity price in years 16-20. Using these assumptions, the unit capacity price is 1.34p/kWh.[33]

The total price is 3.10-3.45p/kWh. At an exchange rate of $1.75/£, the corresponding U.S. prices are $0.0542-$0.0604/kWh. These prices are in 1992 dollars. Adjusting for two additional years of inflation brings the U.K. prices into 1994 dollars: $0.0568-0.0632/kWh.[34] These prices are in the middle to lower portion of our sample of U.S. gas-fired cogeneration and/or combined cycle projects. In our sample of 20 nonpeaker gas projects, four have levelized prices at or below $0.057/kWh and twelve projects have prices higher than $0.063/kWh (Table 3-1). Thus, there is a reassuring amount of consistency between typical U.K. gas fired projects as reported by OFFER and typical U.S. projects as observed in our sample.

[33] If we assumed that these projects earned no capacity price in years 16-20, then the unit capacity price at 80% capacity factor would be 1.20p/kWh.

[34] The U.S. Consumer Price Index for all cities (CPI-W) rose at an average annual rate of 2.3%/year from mid-1992 to mid-1994 (U.S. Department of Commerce, 1994).

Construction of Regression Variables

D.1 Introduction

This appendix describes how we selected and constructed the variables used in our regression analysis. We begin with a description of the process used to calculate contract prices, our dependent variables. We then describe each independent variable. Our discussion of the independent variables follows the same order we used to present variables in Table 3-3.

D.2 Description of Contract Price Calculations

As described in Chapter 2, we culled price data from long term independent power contracts. Our sample includes 26 contracts from ten states (see Table 2-1. Summary Statistics on Contracts). We modeled each contract, separating total price into smaller components to the extent possible. Typically, contracts clearly distinguish between fixed and variable payments. Generally, capacity-related payments comprise most of the fixed payment, and energy-related payments comprise most of the variable payments. However, several of the contracts explicitly or implicitly include some O&M and/or fuel charges in the fixed charge.

From these contracts, we developed the following potential dependent variables for our regressions:

- Total Price (20-year levelized, contract life levelized, or any single year)
- Variable Price (20-year levelized, contract life levelized, or any single year)
- Fixed Price (20-year levelized, contract life levelized, or any single year)

Ultimately, we used 20-year levelized prices. 20-year levelized prices, in contrast to contract-life levelized prices, helps to control for “end effects.” That is, contract life prices make longer contracts with terms greater than 20 years appear more expensive. Also, 20-year levelized prices capture more information than prices from single years; single-year prices, which suppress the full effect of each contract's unique blend of starting values and escalation rates.

D.3 Independent Variables

In Table 3-3, we divided the independent variables into the following categories: (1) Product Heterogeneity, (2) Geographic Heterogeneity, (3) Technical and Economic Change, and (4) Buyer Attributes. The rationale for this categorization is provided in Chapter 3. Our variable descriptions, below, are organized along similar lines. Actual values for most variables used in our regression analysis are presented in Table D-1.

Table D-1. Independent Variables

Project Name	Proj. I.D.	State	TCAP (MW)	Term (yrs)	DSP	PVAR (x100)	SII	COAL PRC	GAS PRC	DIST (Miles)	TRATE	RATE ($/kWh)	SALES (GWh)
Crown Vista	C01	NJ	300	20	1	0	1.36	176	203	NA	0.088	0.092	16,773
Indiantown Cogen	C02	FL	300	30	1	0	0.91	184	221	NA	0.088	0.074	66,862
Chambers (Carneys Point)	C03	NJ	224	30	0	0	1.36	176	203	NA	0.090	0.092	7,757
Brooklyn Navy Yard A	G01	NY	40	33	1	0	1.10	154	232	1,335	0.075	0.122	36,369
Brooklyn Navy Yard B	G02	NY	40	31	1	0	1.10	154	232	1,335	0.075	0.122	36,369
Brooklyn Navy Yard Central	G03	NY	90	31	1	0	1.10	154	232	1,335	0.075	0.122	36,369
Holtsville	G04	NY	136	20	0	0.448	1.10	154	232	1,388	0.071	0.127	16,393
Dartmouth, MA	G05	MA	68	25	1	0.296	1.23	171	239	1,507	0.082	0.108	3,225
Pedricktown	G06	NJ	106	30	0	0.294	1.36	176	203	1,284	0.087	0.092	7,757
Doswell	G07	VA	600	25	1	0.370	1.11	150	210	1,039	0.084	0.059	57,774
Gordonsville/Turbo Power I and II	G08	VA	200	25	1	0.462	1.11	150	210	1,037	0.091	0.059	57,774
Wallkill	G09	NY	150	20	0	0.328	1.10	154	232	1,404	0.085	0.081	4,687
Linden	G10	NJ	614	25	0	0.241	1.36	176	203	1,352	0.092	0.122	36,369
Independence	G17	NY	1,040	40	0	0.220	1.10	154	232	1,591	0.081	0.122	36,369
Panda	G19	VA	165	25	1	0.241	1.11	150	210	943	0.091	0.059	57,774
Richmond Power Ent./SJE Cogen	G20	VA	210	25	1	0.223	1.11	150	210	1,037	0.084	0.059	57,774
Hopewell Cogen	G21	VA	248	25	1	0.172	1.11	150	210	1,039	0.084	0.059	57,774
North Las Vegas	G22	NV	45	30	1	0	1.03	143	180	1,732	0.074	0.052	9,222
Blue Mountain Power	G23	PA	150	20	1	0	0.97	152	296	1,283	0.066	0.068	9,718
Enron	G24	MA	140	20	1	0.067	1.23	171	239	1,507	0.078	0.057	22,213
Tiger Bay	G25	FL	217	30	0	0	0.91	184	221	725	0.090	0.062	27,144
Hermiston	G26	OR	409	30	1	0.096	0.91	109	175	630	0.053	0.043	49,758
Spanaway (Pierce Co.)	G28	WA	240	20	1	0.002	1.04	146	349	760	0.069	0.032	87,600
Commonwealth Atlantic	P02	VA	312	25	1	0.134	1.11	150	210	1,039	0.091	0.059	57,774
Hartwell	P03	GA	303	27	1	0.297	0.97	180	279	612	0.073	0.071	22,197
Franklin & Somerset Co. ME	W03	MA	20	29	0	0	1.23	171	239	NA	0.060	0.057	22,213

Note: First letter of Project ID indicates technology type: C = Coal, G = Gas, P = Peaker, W = Wind.

D.3.1 Product Heterogeneity Variables

Facility Size (TCAP) - measures the size of the generating facility, in GW's. This value is generally the same as contract capacity, except in the case of merchant IPPs.

Contract Term (TERM) - measures the term of the contract in years.

Technology (COAL, PEAK, or WIND) - dummy variables used to distinguish different project technologies. Our sample has four technologies: gas-fired “nonpeaker” (cogeneration and/or combined cycle), gas-fired peaker, coal, and wind. Accordingly, we use three dummy variables to differentiate the four options.

Dispatchability (DSP) - dummy variable that measures differences in buyer's right to economic dispatch. We divided the projects into two categories: full dispatch and partial or minimal dispatch. Accordingly, we use a dummy variable to differentiate these two states, where one equals full dispatch and zero equals partial or minimal dispatch.

An Index to Measuring Sensitivity to Input Price Changes: PVAR

We constructed a variable, PVAR, that provides an indication of a project's sensitivity to changes in fuel prices. We used the following method to construct PVAR:

1. Assume four plausible alternatives to the base-case scenario regarding future gas/oil prices. The base and four alternate scenarios are defined in Table D-2 below. We assigned a probability to each scenario, approximating a normal distribution.

2. Calculate 20-year levelized price for each project under each scenario.

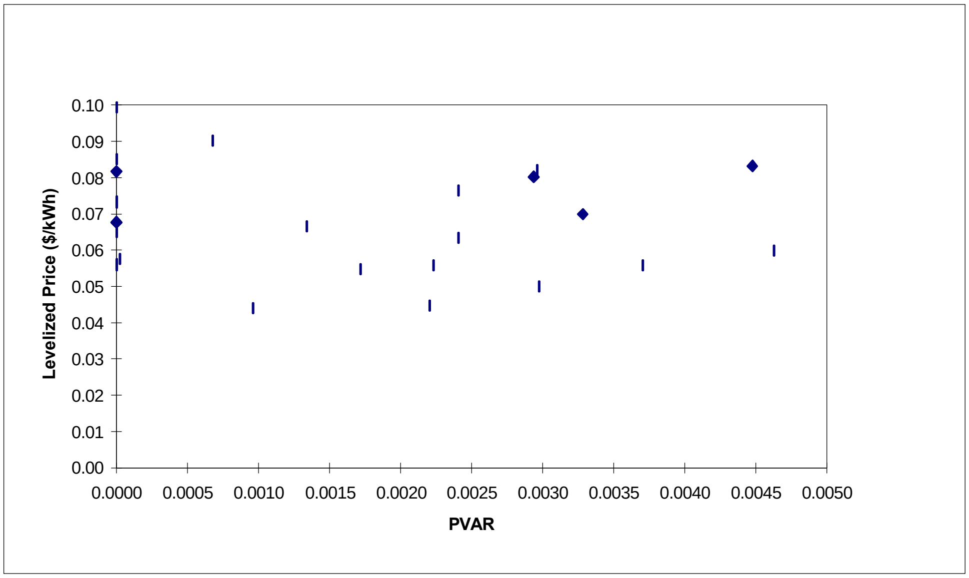
3. Calculate the standard deviation of the five 20-year levelized prices for each project. Assign weights to each scenario's price using the probabilities listed in Table D-2.

Table D-2. Scenarios Used to Calculate Price Variability Index (PVAR)

Scenario	Escalation Rate (%/year)		Probability (weight)
	Real	Nominal (Real + 4.1%/year)	
Low	-2.0%	2.1%	7.0%
Medium Low	-0.5	3.6	26
Base	1.0	5.1	34
Medium High	2.5	6.6	26
High	4.0	8.1	7

The standard deviation calculated for each contract is its PVAR. Thus, a high standard deviation indicates a high degree of sensitivity to input price assumptions. Figure D-1 shows the relationship of project prices and PVAR. In general, we expect projects with high PVAR values to have lower prices; buyers should be less willing to pay for projects with higher uncertainty in future prices. However, Figure D-1 indicates that this is not the case, since there is little relationship between PVAR and price. Sensitivity to gas/oil escalation rates is just one factor that can contribute to changes in future prices. Perhaps purchasing utilities also are concerned with other risks which we have not quantified, such as sensitivity to inflation, coal prices, or regulatory uncertainty (i.e., a low PVAR contract may be harder to justify with regulators even though it reduces fuel price risk to buyer).

Figure D-1. Relationship Between Levelized Price and PVAR



D.3.2 Geographic Definition Variables

Region (NE/SE) - dummy variable that indicates the project's region. We separated states into three regions: northeast, southeast, and west (note: we did not intentionally exclude the Midwest, but none of our projects happen to be in that region). We use two dummy variables, northeast and southeast, to capture regional differences.

Coal Prices Available to Buyer - average coal price in purchasing utility's state for 1991 and 1992, expressed in cents per MMBtu.

Gas Prices Available to Buyer - average gas price in purchasing utility's state for 1991 and 1992, expressed in cents per MMBtu.

Distance to Gas Supply (DIST) - measures the highway miles between generating facility and gas source. This variable is only used for gas-fired projects. Depending on the gas source, distance is either measured from Calgary or New Orleans. Note, we did not use this variable in our final regression model because coal projects do not have a similar variable. This variable was not significant in the gas-only regressions.

Median Per Capita State Income (SII) - index that measures state income. Source: *Statistical Abstract of the United States 1993, Table 319* (U.S. Department of Commerce 1993).

Local Economy-wide Prices - index that measures regional prices. Source: *Statistical Abstract of the United States 1993, Table 763*.

D.3.3 Technical and Economic Change Variables

Interest Rate (TRATE) - measures the 10-year Treasury rate on the contract execution date. Source: *Economic Report of the President 1992*, Table B-69.

Contract Execution Date (CED) - measures the date that the contract was signed. CED is measured using Excel's date function, which converts each date into the number of days since 1900. A contract executed on January 1, 1990 has a date value of 365.25 * 90 = 32,875.5.

Operation Date (COD) - measures the date on which the IPP began (or will begin) selling energy and capacity to the purchasing utility. The date is measured in the same manner as CED.

D.3.4 Other Buyer Attributes, Including Willingness to Pay

Average Rates of Buyer (RATE) - measures purchasing utility's 1990 average retail rates, in $/kWh. Source: *Financial Statistics of Selected Investor-Owned Utilities 1990*.

Annual Sales of Buyer (SALES) - measures total retail 1990 energy sales of purchasing utility, in GWh. Source: *Financial Statistics of Selected Investor-Owned Utilities 1990*.

Standardizing the Price of Power from Intermittent Resources

E.1 Introduction

To compare the price of electricity from intermittent technologies with thermal power projects requires some normalization for differences in reliability and dispatchability. Thermal power projects are dispatchable; i.e. their output can be varied (subject to some constraints) in response to fluctuations in demand. Intermittent technologies, wind, solar and run-of-river hydro, produce output in response to the availability of the underlying resource, not in response to the demand for electricity. This difference means that the value of electricity from thermal and intermittent technologies is fundamentally different, and that the former is worth more than the latter.

An analysis of prices is not meaningful if the value of the products compared is different. Since it is difficult to correct for value differences, an approximation can be developed to standardize the products. In our context this means “firming up” the output of intermittent technologies so that it produces an electricity product that more closely resembles thermal power. There is more than one way to conceptualize the “firming up” process. We introduce a simplified procedure which allows for standardization that is relatively unbiased.

E.2 Conceptual Framework

Our basic approach is to assign some fraction of the costs of gas turbine plants to the cost of intermittents to produce a bundled product that is equivalent to the firm energy product produced by thermal power projects. This approach is more flexible and less biased than alternative approaches such as assigning the costs of storage technologies to intermittent technologies.[35]

We present an explicit expression for our normalization procedure so that the nature of the parameters involved becomes clearer. The functional dependence of unit cost ($/kWh) on output (or capacity factor) is an inherent feature of our formulation of the standardization problem, as it is of our basic comparative method for thermal projects. We capture output (or capacity factor) by the variable x, and the cost of an intermittent technology (as a

35 Although it is often thought that storage is an appropriate way to “firm up” intermittent technologies, the economics of storage are complex and they involve system-wide benefits which are separate from the intermittent issues. Therefore, assigning storage costs to intermittents may well add costs that are not associated with the intermittent problem. We avoid this bias by focusing on gas turbines as back-up sources.

function of *x*), by *C(x)*. We define the *Equivalent Thermal Cost* (*ETC*) by the following expression:

$$ETC = C(x) + \alpha\,(GT_{fc})/x + \beta\, GT_{oc},$$

where:

x = annual hours of operation[36]

$C(x)$ = unit cost

Gt_{fc} = fixed costs of a gas combustion turbine.

GT_{oc} = operating or variable costs of gas combustion turbines.

α = (1 - capacity credit), or that fraction of gas turbine capacity that would be required to back up intermittent output.

β = the fraction of x when the gas turbine would actually need to operate to produce the back-up service.

The parameter α is the additive inverse of the capacity credit assignable to the intermittent technology. *Capacity credit* is a system-specific value that depends upon resource characteristics, technological parameters and utility system characteristics. The parameter β is the operating counterpart to α. If α can be thought of as that fraction of gas turbine capacity that must be dedicated to backup the intermittent technology, β represents the fraction of time that backup energy must be supplied because the intermittent source is not able to produce. In theory, we should include a term that credits the ETC for power sold at times when there is no demand. We assume this credit is zero.

E.3 Illustrative Calculation

We use values from our sample data in the ETC formula to illustrate estimation problems associated with our approach.

36 Since we are always normalizing projects to a per kWh basis, the variable x has a natural interpretation as hours of operation per year.

For C(x) we adopt the levelized price for the Kenetech-NEP wind contract (W03), namely \$0.059/kWh, and x = 3,200 hrs/yr.[37] For GT_{fc} we use the costs of the Commonwealth Atlantic project. Commonwealth Atlantic is preferable to Hartwell due to load characteristics. New England experiences both summer and winter peaking loads. Commonwealth Atlantic is designed to serve both summer and winter peaking loads, while Hartwell will operate in a summer peaking region. A gas-fired peaking plant in New England (the location of the Kenetech project) would have to secure firm gas transportation service in order to meet winter demand. Hartwell is able to operate without obtaining firm gas transportation service, thus disproportionately lowering its fuel costs. A more detailed discussion of Hartwell s fuel costs appears in Chapter 3.

For Commonwealth Atlantic, fixed costs are \$68/kW-yr, and levelized variable costs, GT_{oc}, are \$0.052/kWh. Using these values we parameterize ETC over a range of values for α and β. The resulting values range from \$0.072/kWh to \$0.104/kWh. The low value corresponds to a case where $\alpha = 0.5$ and $\beta = 0.05$. This is extremely optimistic with regard to performance. The pessimistic case corresponds to $\alpha = 1$ (there is no capacity credit for the intermittent technology) and $\beta = 0.45$ (the back up must operate nearly half the time). A central case is $\alpha = 0.75$ and $\beta = 0.25$, which results in ETC = \$0.088/kWh.

For comparison purposes, combined cycle projects operating 3,500 hours, i.e., at 40% capacity factor, would have a range of levelized costs, as is shown in Table 3-1. A relatively low cost project, such as Doswell (levelized energy costs of \$0.033/kWh and capacity costs of \$171/kW-yr) would have a levelized cost of \$0.082/kWh at 40% capacity factor. This is similar to our central estimate of the ETC for the wind project. Costs in New England tend to be high, so a more appropriate comparison would use the average price of a combined cycle project, \$240/kW-yr for fixed costs and \$0.035/kWh for energy costs. At a 40% capacity factor, these costs result in a price of \$0.101/kWh, which is about the same as the pessimistic ETC for the wind contract.

E.4 Make Up Energy

The comparison of combined-cycle prices with the wind ETC central case does not necessarily mean that a lower ETC cost represents the better alternative, because there is still an underlying demand question; i.e. whether there really is demand for 40% capacity factor electricity. One way to address the potential mismatch between the demand for electricity and the availability of output from intermittent technologies is to use the concept of make-up energy. This normalization technique has been used in competitive solicitations for power (Consolidated Edison Company 1990). As applied in that setting, the notion was

[37] The operating hours assumption is substantially more optimistic than standard near term expectations for wind turbine generators, which assume about 2100 hours (Cohen, 1993).

to standardize all projects to 8,760 hours per year by adding projections of short-run system marginal cost to resources with less output. That technique assumes both that 8,760 hours/year is the electricity product demanded and that system marginal cost estimates are readily available. Neither may be the case (for very different reasons, of course).[38] Nonetheless, this concept can be adapted to the demand normalization problem if we assume that the conventional thermal project represents the opportunity cost.

Let us formalize the comparison. As before we denote by ETC the calculation outlined in above. We interpret x as hours per year as before. We denote by y the number of hours per year of electricity service demanded. We assume $x \langle y \leq 8{,}760$. The conventional thermal project (CTP) which represents the alternative to the intermittent technology has fixed costs *FC* and variable costs *VC*, which we assume are appropriately levelized over the life of the project. The following expression indicates when the costs of the intermittent and the conventional projects are the same.

$$\frac{ETC \cdot x \ + \ MC \cdot (y - x)}{y} = FC/y \ + \ VC$$

In this expression $MC = MC(x,y)$, that is, the relevant short run marginal cost depends on both x and y.

We can re-arrange the make-up energy expression into the following form:

$$(ETC - MC) \cdot x + (MC - VC) \cdot y = FC$$

or

$$y = \frac{FC - (ETC - MC) \cdot x}{(MC - VC)}$$

By plugging values into the final equation, we can solve for the value of y where wind becomes competitive. To do this, we use the following values:

- The central case in the numerical example for the calculation of ETC for the Kenetech-NEP contract (i.e., \$0.088/kWh),
- Values for FC and VC equal to average contract prices for combined-cycle projects, and
- An assumption that the relevant levelized MC over the (y - x) hours is \$0.06/kWh.

[38] For a critique of the 8760 hours assumption see Section 5.3.1 of Goldman *et al* (1993).

The result is y = 6,267 hours. For MC equal to $0.07/kWh, the corresponding value of y is 5,365 hours. These calculations suggest that the intermittent technology is economic under the assumed cost conditions if incremental demand for electricity is at or above the load factors corresponding to the estimates of y; i.e. 72% in the case y = 6,267 hours and 61% for y = 5,365 hours. All of this subject to the accuracy of the corresponding MC estimate.

An alternative approach to the comparison of wind projects with conventional thermal alternatives is to recognize that thermal capacity is typically added to provide baseload energy. Under this interpretation, we can therefore assume that we know the value of y and then check to see what value of MC corresponds to that. The upper bound on y is 8,760 (i.e. if the conventional thermal alternative operated all year, without forced or scheduled outages). At that level of operation, the indifference point for the conventional alternative (i.e. at average contract prices for combined cycle projects) and the Kenetech-NEP windpower contract comes at MC equal to $0.0493/kWh. At any MC less than this, the wind contract is cheaper than a typical combined-cycle facility operating at a 100% capacity factor.

E.5 Conclusions Regarding Standardization Methods

These calculations show the conceptual difficulty of achieving a standardization for intermittent resources. The basic problem is that cost comparisons alone are inadequate. There needs to be a value dimension brought into the analysis. The value dimension, measured by the demand and marginal cost parameters, are much more difficult to estimate than contract costs. As a result only the broadest general conclusions are possible with the approach outlined here. These include:

> The Kenetech-NEP project looks reasonably competitive against average priced conventional thermal alternatives, as long as the back up requirements are not large.
>
> The Kenetech-NEP wind project is uncompetitive only if back up requirements are large or if it has to compete with the cheaper thermal projects in the sample.
>
> No simplified methodology which is based on cost alone can provide useful comparisons.