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Alternative Windpower Ownership Structures: Financing Terms and Project Costs

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All remaining errors and omissions remain the responsibility of the authors.

Acronyms and Abbreviations

AMT	Alternative Minimum Tax
AWEA	American Wind Energy Association
BPA	Bonneville Power Administration
CARES	Conservation and Renewable Energy Systems
CRF	Capital Recovery Factor
DSCR	Debt Service Coverage Ratio
EPAct	National Energy Policy Act of 1992
EPRI	Electric Power Research Institute
EWEB	Eugene Water and Electric Board
IOU	Investor-Owned Utility
IR	Interest Rate
IRRC	Investor Responsibility Research Center
JPA	Joint Powers Authority
kWh	Kilowatt-hour
MACRS	Modified Accelerated Cost Recovery System
mill	One-tenth of a cent
MW	Megawatt
NIEP	National Independent Energy Producers Association
NSP	Northern States Power
NUG	Non-Utility Generator
O&M	Operation and Maintenance
OTA	Office of Technology Assessment
PGE	Portland General Electric
PPA	Power Purchase Agreement
PSCo	Public Service of Colorado
PTC	Production Tax Credit
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act
REPI	Renewable Energy Production Incentive
RFP	Request for Proposals
ROE	Return on Equity
RR	Revenue-Requirement
SCE	Southern California Edison
SMUD	Sacramento Municipal Utility District
UWIG	Utility Wind Interest Group
WACC	Weighted Average Cost of Capital

Executive Summary

Introduction

Most utility-scale renewable energy projects in the United States are developed and financed by private renewable energy companies. Electric output is then sold to investor-owned and public utilities under long-term contracts. Limited partnerships, sale/leaseback arrangements, and project-financing have historically been the dominant forms of finance in the windpower industry, with project-finance taking the lead more recently. Although private ownership using project-finance is still the most popular form of windpower development, alternative approaches to ownership and financing are becoming more prevalent.

U.S. public and investor-owned electric utilities (IOUs) have begun to participate directly in windpower projects by owning and financing their own facilities rather than purchasing windpower from independent non-utility generators (NUGs) through power purchase agreements (PPAs). In these utility-ownership arrangements, the wind turbine equipment vendor/developer typically designs and constructs a project under a turnkey contract for the eventual project owner (the utility). The utility will also frequently sign an operations and maintenance (O&M) contract with the project developer/equipment vendor.

There appear to be a number of reasons for utility involvement in recent and planned U.S. wind projects. One important claim is that utility ownership and self-finance provides substantial cost savings compared to contracting with private NUGs to supply wind-generated power. In this report, we examine that assertion.

Approach

We analyze the costs of utility-scale windpower projects under different types of ownership structure and market scenarios. Specifically, we compare the nominal levelized 20-year cost of windpower under three general types of ownership and financing structure: (1) private ownership, project-finance; (2) investor-owned utility ownership, corporate-finance; and (3) public utility ownership, tax-exempt bond finance. The final category, public ownership, is split into two financing arrangements, namely internal- and project-finance. The key difference between these two financing types is the extent to which the public utility provides additional security and collateral to the lender other than the power project itself and its power purchase contract.

To model the cost and financing variables, we developed three 20-year financial cash-flow models (one for each of the ownership and financing arrangements) using a hypothetical 50 Megawatt (MW) windpower facility with specified operating and cost inputs. Each spreadsheet model was developed to replicate as closely as possible actual utility and developer cost estimation techniques: (1) a pro-forma cash-flow model is used to assess private ownership, project-finance arrangements; (2) a revenue-requirements model is developed for the IOU ownership and finance scenario; and, (3) a cash-flow model is created to evaluate the public ownership scenarios. The key financing and tax differences among the various ownership and financing structures are summarized in Table ES-1.

Table ES-1. Key Financing and Cost Differences Among Windpower Ownership Structures

			Public Ownership	
Variable	Private Ownership	Iou Ownership	Internal-Finance	Project-Finance
Capital Structure	Flexible--Can optimize to minimize cost	50% equity 50% debt	100% debt	100% debt
Debt Interest Rate	9.5%	7.5%	5.5%	7.5%
Debt Amortization Period	12 years	20 years	20 years	20 years
Debt Amortization Schedule	Mortgage-Style Repayment	Straight-Line Declining Rate-Base	Mortgage-Style Repayment	Mortgage-Style Repayment
Debt Service Coverage Ratio Requirements	Minimum 1.4	No project-specific requirement	No project-specific requirement	Effectively, no project-specific requirement
Equity Cost	18%	12%	n/a	n/a
Property Tax	Levied on total value of facility	Levied on total value of facility	Levied only on value of land	Levied only on value of land
Income Tax	5-yr Depreciation	Normalized, 7-yr Depreciation	None	None
Production Credit	PTC for 10 years	PTC for 10 years	REPI subject to yearly allocation	REPI subject to yearly allocation

We estimate the levelized cost of windpower in the public ownership scenarios under two input cases. The first assumes full expectation of receiving the 10-year, 15 mill/kWh federal renewable energy production incentive (REPI). The second assumes that the utility has no expectation of receiving any outlays from this program. Unlike the production tax credit (PTC) provided to private and IOU windplant owners, the REPI funds are subject to yearly Congressional appropriation. Because of the uncertainty associated with this process, public utility windpower projects are typically not evaluated as if the credit was assured.

Windpower Project Costs Under Various Ownership Structures

In Table ES-2, we present the apparent cost of windpower facilities constructed under the basic ownership and financing scenarios. All results are presented as 20-year nominal levelized costs in 1997 dollars. Capital structure for the IOU and public utility ownership scenarios is fixed. Capital structure in the private ownership, project-finance structure is variable, and is optimized to minimize the levelized cost of energy. Although the absolute value of these levelized cost estimates depends on project-specific input cost and performance assumptions, the relative cost advantages shown below should not be substantially affected by these input assumptions.

Table ES-2. Effects of Ownership Structure on Windpower Project Cost

Ownership/ Financing Scenario	Levelized Cost of Energy (mills/kWh)	% Cost Savings Compared to (1)
(1) Private Ownership, Project-Finance	49.5 (53% equity)	n/a
(2) IOU Ownership, Corporate-Finance	35.3	29%
(3) Public Utility Ownership, Internal-Finance		
a. w/ REPI	28.8	42%
b. w/o REPI	43.5	12%
(4) Public Utility Ownership, Project-Finance		
a. w/ REPI	34.3	31%
b. w/o REPI	48.9	1%

Assuming that the installed and general O&M costs are equal in all ownership scenarios, and using these economic and financial analysis techniques, we conclude that utility ownership of windpower facilities results in a significantly lower estimated levelized cost of energy. Compared to the private ownership, project-finance structure, IOU ownership reduces apparent levelized costs by approximately 30% (14 mills/kWh). Internally-financed public utility ownership is estimated to reduce overall costs by approximately 10-40%, depending on whether the REPI payments are included in the analysis. Similarly, project-financed public utility ownership is expected to reduce costs by 0-30%. These results likely provide an upper bound to the potential cost savings associated with utility ownership because turbine mark-ups and performance guarantees would likely result in higher input costs in the utility ownership arrangements than in the private ownership scenario.

This analysis suggests that the most common form of U.S. windpower development, namely private NUG ownership and project-financing, is also the most costly type of windpower ownership and finance of those options considered here. Based on our sensitivity analysis, we conclude that the primary benefits associated with public ownership and finance come from the lack of project-specific minimum debt service coverage ratio (DSCR) requirements, which allows an increased level of debt in the capital structure, reduced debt costs, and an increased debt amortization period. The benefits of IOU ownership and finance come primarily from debt and equity cost reductions, longer debt amortization, and the lack of project-specific DSCR requirements.

The tendency for developers to maximize low-cost debt in the capital structure of privately-owned power facilities is limited by debt service coverage requirements imposed by the lender. This constraint often binds in the first years of operation, resulting in a *"first-year* DSCR constraint" that has historically been a barrier to private power development by reducing debt leverage and increasing levelized costs. It appears that windpower developers have been largely successful in mitigating this constraint in recent years through front-loading of contract payments and/or back-loading of debt repayment. Our base-case NUG windpower cash-flow model assumes contract payment front-loading by using a constant nominal (not inflation adjusted) PPA energy price. Sensitivity analysis demonstrates that first-year constraint mitigation (such as that used in our base-case results) can reduce costs by approximately 10% (5 mills/kWh).

It is important to consider whether utility ownership and self-financing of wind turbine power-plants (or any power-plant, for that matter) is truly cheaper than power purchases from entities using project financing or, instead, if utility ownership and economic analysis simply conceals the true costs and risks of wind development. The cost savings of utility ownership are at least partially offset by the increased risk to utility shareholders and ratepayers in utility-ownership scenarios. Specifically, ownership of power facilities results in an increased performance risk liability compared to contracting with independent power suppliers through power purchase agreements. Performance guarantees and fixed-price O&M agreements can be used to reduce ownership risks, but these are only available at a cost. Furthermore, our analysis suggests that some of the estimated and claimed cost savings from utility ownership are simply a result of suboptimal utility analysis procedures. The overall credit rating of the company is used to estimate debt and equity costs in IOU and internal-finance public ownership arrangements, rather than the project-specific debt and equity costs used in stand-alone, private ownership cost analysis. IOU and public utility cost-estimation techniques therefore use utility average bond and equity costs and terms, ignoring the variance in risks associated with different projects, and therefore the marginal impact of different investments on financing costs. As electric restructuring proceeds, utility analysis techniques may approach those used by NUGs, and the apparent cost-savings advantages of utility ownership may diminish.

Value of the Federal PTC and REPI

The federal PTC and REPI were enacted to stimulate domestic wind development, and were designed so that all owners of windpower facilities would be treated more-or-less equally. Our analysis demonstrates that these incentive schemes were not structured properly to meet the competitive neutrality objective. First, the REPI payment (provided to public owners of windplants) is subject to greater budget uncertainty than the PTC (supplied to private and IOU owners). Second, to the extent that not all investors can absorb the full tax advantages afforded by the federal tax credit, the PTC value is reduced. Finally, the secondary effects associated with receiving the PTC alter its value from the 15 mill/kWh direct tax subsidy it was intended to provide. These secondary effects include impacts on capital structure and the secondary tax benefits of obtaining the PTC. Our analysis suggests that the production incentive is most valuable to IOUs, moderately valuable to private windplant owners, and least useful in public utility ownership.

Impact of Technology and Resource Risk: The Wind Financing Premium

Due to the real and perceived risks associated with wind turbine technology and wind resources, privately owned and financed wind projects typically receive financing that is both more costly and restrictive than is available to more traditional gas-fired generation sources. Using our pro-forma cash-flow model, we conclude that the financing advantage afforded to gas-fired NUGs is significant. If wind developers received similar financing terms and costs as gas-fired NUGs, the nominal levelized cost of windpower might decrease by 25% (12 mills/kWh) compared to our base-case private ownership results. As wind turbine technology matures, resource evaluation becomes more accepted, and information becomes readily available to the financial community, debt and equity costs and terms may become less restrictive and costly for project-financed windpower facilities. These risks may never drop to a level equivalent to that of gas-fired power-plants, but significant reductions in financing costs may be achieved. Additionally, there are a number of policy approaches that could be used to either directly reduce finance costs or indirectly reduce costs by reducing project risks.

Electric Industry Restructuring

Windpower project costs are particularly sensitive to financing terms and conditions, and can vary by up to 40% by a simple change in ownership and financing structure. Our analysis suggests that apparent windpower costs can be reduced through utility ownership and self-financing arrangements. Electric utility restructuring could, however, fundamentally change the financing of power projects in general, and windpower projects in particular. It could also result in altered utility cost-estimation techniques. Unfortunately, the ultimate consequences of industry restructuring are indeterminate. Regardless of the outcome of this process, however, it seems unlikely that restructuring will halt all direct investment by investor-owned and public utilities in power projects. If the private ownership model continues to dominate the wind development market, however, additional policy mechanisms may be required in a post-restructuring era to either: (1) preferentially provide longer-term power contracts to wind owners; or, (2) provide sufficient guarantees or cost incentives such that long-term power contracts are less essential in project development.

Introduction

This report examines the implications of financing and ownership structure on the apparent levelized cost of utility-scale windpower projects. Due to the high capital costs associated with windplants and their inherent and perceived resource and technology risks, finance costs are of significant import to windpower facilities.

We focus on the effects of project ownership and finance structure on the overall cost of windpower supply. Until recently, almost all utility-scale windpower projects were developed and financed by private renewable energy companies (non-utility generators), often through project-finance structures. In this arrangement, power-plants are financed on a non-recourse basis, and lender and equity security is provided solely through the assets and cash flows of the project itself. Electric output is sold to investor-owned and public utilities under long-term contracts. Although still the most popular form of windplant development, alternative forms of ownership and financing are now being considered and used. Specifically, U.S. public (primarily municipal) and investor-owned electric utilities (IOUs) have begun to express interest in owning and financing their own wind facilities rather than purchasing windpower from independent non-utility generators (NUGs) through power purchase agreements (PPAs).

There are a number of reasons for utility involvement in recent and planned U.S. wind projects, but the apparent cost savings associated with utility ownership and finance compared to contracting with private NUGs to supply windpower is one of the most often stated justifications. These cost savings are claimed to come from the lower cost debt and equity capital sources available to investor-owned and public utilities, the longer maturities typical of utility debt, the tax exemptions available to public utilities, and the requirement only to reach a certain utility-wide debt-service coverage level rather than meet project-specific lender constraints.

This report estimates the apparent[1] levelized cost of energy from utility-scale windpower projects under different types of ownership structure and market scenarios. Specifically, we compare the nominal levelized 20-year cost[2] of a 50 megawatt (MW) windpower facility under three general types of ownership and financing structure: (1) private ownership, project-finance; (2) investor-owned utility ownership, corporate-finance; and (3) public utility ownership, tax-exempt bond finance. The final category, public ownership, is split into two

1 "Apparent" levelized cost is meant to identify the cost calculated using traditional cost-analysis techniques. To the extent that these techniques are suboptimal, the estimated (or apparent) levelized cost may differ from the actual project cost.

2 In estimating the "cost" of a facility, we include only the private cost paid by the utility for the power. In the private ownership case, we actually determine the contract price that the plant must receive to meet input cost and financing requirements. We assume that this price is equal to the cost to the utility (or ratepayer) for the power.

financing arrangements, namely internal- and project-finance. To model the cost and financing variables, we develop three cash-flow models, one for each of the general ownership and financing arrangements. Each model was created to closely replicate the actual type of analysis performed by the ownership-entities when considering the cost of power facilities. A pro-forma cash-flow model is used in the private ownership, project-finance arrangement. A revenue-requirement model is developed for the IOU ownership, corporate-finance structure. Finally, a simple cash-flow model is created to evaluate both internal- and project-financed public ownership.

We then explore a number of scenarios to evaluate the robustness of our base-case results and describe the nature and magnitude of the financing constraints. We also analyze and discuss several additional policy-related issues associated with windpower finance, including: (1) the extent to which the calculated cost savings of utility ownership are due to real financial cost reductions rather than suboptimal analysis procedures; (2) the increased incidence of utility and ratepayer risk in utility-ownership scenarios; (3) the value of the federal production tax credit (PTC) and renewable energy production incentive (REPI); (4) the financing premium paid by private wind owners compared to traditional NUG gas-fired generation facilities; and, (5) the effect of utility restructuring on windpower finance and our alternative ownership results.

The remainder of this report is organized in the following fashion. After providing a brief background to windpower finance and ownership, Chapter 2 describes the three ownership and financing arrangements, introduces and provides estimates for the basic financing terms and variables, lists the windpower cost, tax, and performance inputs to each cash-flow model, and briefly introduces the cost-estimation models used in the report. Chapter 3 presents the results of our analysis on the effects of ownership and finance structure on windpower costs, and identifies the driving forces behind the results. Chapter 4 discusses several interesting aspects of the ownership structure analysis, and extends the private ownership, project-finance model to consider several other policy-related aspects of windpower finance. Appendix A provides a brief history of windpower finance, and Appendix B describes recent utility involvement in wind development. In Appendix C, a detailed description of the cash-flow models developed and used in this report is presented.

Alternative Ownership Structures, Financing Terms, and Model Inputs

2.1 Overview

In this chapter we: (1) describe the various ownership and financing options assessed in this report; (2) define the basic terms associated with financing power-plants; (3) estimate values for these financial variables under each ownership structure; (4) list our project, cost, tax, and operating cash-flow model input assumptions; and, (5) briefly describe the three primary cash-flow models developed and used in this report. Appendix C describes, in detail, the specifics of the cash-flow models, and also includes base-case model runs. In Section 2.2, we provide background on windpower finance and ownership. In Section 2.3, we discuss the most common form of windpower development structure, private ownership and project-finance. Section 2.4 characterizes IOU ownership and corporate-finance. Section 2.5 then discusses public utility ownership and tax-exempt bond finance. We evaluate two financing variations to public utility ownership: (1) internal, or "corporate," finance; and, (2) project-finance. Section 2.6 describes and provides empirical estimates for the financing terms used in each ownership scenario. Estimates come from a variety of sources, including personal communications with wind project developers, investor and public utilities, investment banks and lenders, and various publications. Section 2.7 lists our assumptions on windpower operations, wind facility capital and operating costs, and windplant tax treatment. Section 2.8 briefly describes the three cash-flow models.

2.2 Background

This section provides a cursory background to U.S. windpower development, and recent utility interest in windplant ownership (see Appendix A for a more complete history of windpower finance in the U.S., and Appendix B for specific utility activity in the ownership and finance of recent and planned windplants).

Prior to the mid-1980s, almost all windpower development occurred through tax-advantaged limited partnerships of third-party individual investors. Sale/leaseback structures were popular in the mid- to late-1980s, but more traditional project-finance with independent debt and equity investors has now become the dominant form of windpower development in the U.S. Most recently, however, utilities have begun to consider participating directly in windpower development by taking ownership of windplants. In these utility-ownership and finance arrangements, the wind turbine equipment vendor and developer will typically design and construct a project under a turnkey contract for the eventual project owner (the utility). The utility will also frequently sign a fixed-price operations and maintenance contract with the project developer/equipment vendor to minimize utility operations risk. Although a number of utilities own small wind installations, few have a direct ownership interest in large-scale (over 5 MW) windplants. One exception is the Sacramento Municipal Utility District (SMUD), which currently owns a 5 MW facility, with planned additions of another 45 MW. A number of utility-owned and financed projects are currently in the development stage. Approximately half of the windpower capacity in the later stages of development in the U.S. is for utility-owned facilities (see Appendix B).

2.3 Private Ownership, Project-Finance

Unlike corporate-finance, private power producers have generally financed projects on a stand-alone basis. In these project-finance arrangements, the lender looks primarily to the cash-flow and assets of a specific project for repayment rather than the assets or credit of the promoter of the facility. The strength of the underlying contractual relationship between different parties is essential. Credit support for project-finance comes in large part from the revenues associated with the power purchase agreement.[3] Because most markets do not provide long-term fixed-price contracts, project-finance is most typically associated with power generation and several other specific commodities (Kensinger and Martin, 1988; Nevitt, 1983).

In this situation, the lender's problem is to assure that revenues from the single asset, in this case a wind turbine power-plant, will be sufficient to meet all debt service obligations (i.e., to repay the loan). Ultimately, repayment depends upon the economic viability of the project. To provide assurance that project performance requirements are met, lenders typically include extensive restrictions, called loan covenants, in their agreements with borrowers. These covenants are often more restrictive than those found in corporate-finance bond offerings. Our analysis includes the most important of these project-finance loan covenants, namely debt service coverage requirements (see Section 2.6.4 for a more detailed discussion).

Project-financing has been used extensively by private power producers and windpower developers. In some cases, project-finance is the only alternative for renewable energy producers because they often do not have the assets, track record, or credibility to obtain corporate-financing on favorable terms. From the developer's perspective, project-financing does provide some benefits, however, compared to corporate-finance. First, project-finance is generally non-recourse (sometimes limited recourse) to the parent company and therefore does not have a substantial impact on their balance sheet or creditworthiness. Second, the greater debt capacity typically associated with project-finance can result in reduced financing costs because debt funds are frequently less costly than equity. Consistent with industry practice, developers using project-finance typically seek to maximize the fraction of debt in

3 Tax credits only provide a return to equity investors and do not supply credit support to project lenders.

the capital structure of their projects subject to lender constraints. The most important lender constraint is the debt service coverage ratio (DSCR).

Nevitt (1983) discusses the negative aspects of project-finance, which include the large transaction costs associated with arranging the various contracts, high legal fees, higher debt and equity costs, and a greater array of restrictive loan covenants.

2.4 Investor-Owned Utility Ownership, Corporate-Finance

IOUs depend primarily on corporate-finance structures, which rely on the attractiveness of a firm's balance sheet and prospective cash-flows. Therefore, when IOUs borrow money from public markets, the support for their credit comes from the income stream of their entire asset base (generation, transmission, and distribution), not an individual project. Corporate lending therefore lacks the degree of specificity found in project-finance. Similarly, equity contributions in corporations differ from those in project-financed power facilities because returns are based on the multiple income streams of the company's asset base, not an individual project.

Unlike project-finance investors, corporate issues of publicly sold bonds typically contain few restrictive covenants. The primary covenant is a restriction on issuing debt beyond certain limits (Smith and Warner, 1979). Additional debt can hurt bondholders because it reduces the ability of the firm to pay interest on existing debt. This capital structure requirement acts as an implicit company-wide DSCR constraint.

There is an extensive literature on the question of capital structure and the relative costs of IOU corporate-finance and NUG project-finance (Raboy, 1991; Perl and Luftig, 1990; Conway and Hausker, 1991; Naill and Dudley, 1992; NIEP, 1991; Kahn *et al*, 1992). Debt and equity investors in IOUs typically require lower returns than investors in individual power projects due to the asset diversity of corporate-finance, the increased liquidity and information flow associated with public markets, the franchise monopoly provided to IOUs, and the implicit social contract with regulatory agencies to maintain the existence of firms barring catastrophic events. Compared to NUG developed, project-financed facilities, the benefits associated with IOU corporate-finance include:

(1) Lower interest rate debt;
(2) Longer debt amortization;
(3) Lower cost equity; and,
(4) No project-specific debt service coverage requirements.

NUGs using project-finance often attempt to maximize debt subject to lender DSCR requirements. Electric utilities do not have this flexibility, and typically maintain conservative debt-equity ratios. The most important cost of IOU ownership and finance is therefore a less flexible capital structure (i.e., typically greater use of higher cost equity).

For federal income tax purposes, private windplant owners receive 5-year accelerated depreciation for wind equipment. IOU owned windpower facilities are likely to receive 7-year accelerated depreciation, resulting in a slight disadvantage compared to the NUG ownership scenario. IOUs also use tax normalization to calculate yearly income tax expenses, described in Appendix C. The determination of whether and to what extent IOU owned and financed windpower projects reduce apparent levelized costs will depend on the relative effects of these variables.

2.5 Public Utility Ownership, Tax-Exempt Bond Finance

Public utility owned windplant costs are expected to be significantly lower than for privately owned facilities due to the asset diversity associated with some forms of public finance, the franchise monopoly provided to public utilities, the quasi-monopoly ratemaking authority of these entities, the tax-exempt nature of public utility debt, and the tax exemptions provided to these utilities. The primary ownership and finance benefits associated with public utility power-plant development include:

(1) Debt is tax-exempt, therefore reducing its cost;
(2) Longer debt amortization;
(3) Greater use of debt in the capital structure (effectively 100% debt);
(4) No project-specific debt service coverage requirements;
(5) No income taxes; and,
(6) Reduced property taxes.[4]

There are two primary costs associated with public finance. First, because income taxes are not paid, public utilities do not gain some of the tax advantages afforded to private owners of windpower facilities, namely accelerated depreciation and the federal production tax credit (PTC). Second, although public entities can obtain an equivalent cash production incentive in lieu of the PTC, the yearly funding for this payment is highly uncertain.

Public entities can and have used both internal- and project-finance structures for power-plant development. Internal, or "corporate," financing has been the most common, and is the type of financing used for the first 5 MW of the SMUD windpower project. When a public utility borrows money from public markets, the support for their credit comes from the income stream of their entire asset base, not an individual project. As in IOU corporate-finance, the

4 Unlike private power and IOU projects, public entities typically expect to pay property taxes only on the unimproved value of the land, not on the increased value of the windpower facility (Olmsted, 1995; Wolff, 1995).

total income stream is typically diversified by the inclusion of many assets. In this structure, financing for individual projects comes from internal funds and the issuance of additional tax-exempt bonds by the utility. Although these bonds do, typically, have DSCR requirements, these requirements are company-wide constraints and are not project-specific (see Section 2.6.4).

To reduce "corporate" liabilities and risks, public utilities have also used project-financing in recent power-plant development. In this scenario, the public utility creates a subsidiary to own and finance the power project, and arranges to purchase power from the entity through a power purchase contract. Similar to internal-finance, the subsidiary will typically use 100% tax-exempt debt financing, but security for the bonds comes only from the revenue stream of the project. Debt service coverage requirements (imposed on the subsidiary) are similar to those in private ownership, project-finance arrangements. Project-financing is typically more costly than internal-finance because debt costs are higher due to project specificity and a reduction in security. The public utility risk reduction benefits of these arrangements often exceed their costs, however. SMUD has used this finance mechanism extensively, forming independent subsidiaries, called Joint Powers Authorities (JPAs), to own and finance power projects.[5] They are considering a JPA arrangement for the second 45 MW phase of their Solano windplant (Olmsted, 1995).

FloWind is developing a project in Eastern Washington for a public entity (the Conservation and Renewable Energy Systems--CARES) with the support of the Bonneville Power Administration (BPA). The project plans to use a financing approach that is a hybrid structure of the two described above. CARES is a joint operating agency whose members consist of eight Washington public utility districts. CARES will own and finance the 25 MW FloWind windpower facility, but will not do so through typical project-finance mechanisms. Although security for the tax-exempt bonds include the project's PPA (similar to project-finance), the BPA is also backing the bonds, therefore reducing the risk of bond default (Wolff, 1995).

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5 For example, the Central Valley Financing Authority was created by SMUD and the Sacramento Regional County Sanitation District to own, finance, and construct the Carson Ice-Gen Cogeneration Project. A bond prospectus was released in 1993 (Central Valley Financing Authority, 1993).

2.6 Financial Terms and Variables: Description and Empirical Estimates

2.6.1 Capital Structure

Capital structure refers to the mix of debt and equity that is used to finance projects or firms. For a good theoretical introduction to the tradeoffs between and benefits of debt and equity, see Brealey and Myers (1991). Although there is a substantial literature addressing the determinants of capital structure, Brealey and Myers (1991) conclude that no coherent theory of capital structure yet exists.

Despite the theoretical debates, what is clear is that capital structure differs markedly among the three basic ownership and financing structures assessed in this report. Developers using project-finance structures generally try to maximize the fraction of debt in the capital structure of their projects, subject to the constraints that lenders will tolerate. The most important of these lender constraints, discussed in more depth in Section 2.6.4, is the minimum debt service coverage ratio. Although equity costs are likely to rise with debt fraction (due to the increased risk of default), industry practice in maximizing debt seems to indicate that this counter-effect is relatively minimal. Debt fractions of 80% are common in recent U.S. gas- and coal-fired NUG power projects (Kahn *et al.*, 1992).

Data availability on privately owned, project-financed windpower debt-equity ratios is limited. Although debt leverage of up to 70% was perhaps cost-minimizing prior to the enactment of the 15 mill/kWh production tax credit for windpower projects, the equity fraction has likely increased since that time. A production tax credit only benefits equity investors, and cannot be used to service debt or help mitigate DSCR constraints. Kahn (1995) analyzes this issue, and estimates that if the incentive were paid in the form of a direct cash payment rather than as a reduction in income taxes, the optimal debt fraction of a windpower project would increase by 0.2. This estimate seems to be validated by industry practice. Wong (1995) believes that U.S. windpower debt-equity ratios of 70%/30%, typical in the late 1980s and early 1990s, are now in the 50%/50% range solely because of production tax credit effects. Consistent with industry practice, the pro-forma cash-flow model used in our analysis optimizes debt-equity ratios in the private ownership, project-finance scenario based on debt and equity costs and the minimum DSCR requirement (i.e., the cost-minimizing debt fraction will be determined).

IOU's have significantly less freedom in determining capital structure. The corporate capital structure is determined by both lenders and regulators, and this structure is typically assumed when assessing various power supply options. IOU's have three primary forms of capital: (1) common shares; (2) preferred shares; and, (3) debt. We assume a 50% equity, 50% debt capital structure, which is consistent with industry practice (EPRI, 1993).

Public utilities (project- and internally-financed) also do not have much flexibility in determining capital structure. Public utilities generally obtain the bulk of their funds through tax-exempt bonds, and therefore effectively have capital structures consisting of 100% debt. Public utility owned and financed power facilities are therefore often evaluated under the assumption of 100% tax-exempt debt. Exceptions do exist, however. When evaluating internally-financed projects, SMUD currently assumes a debt-equity ratio of 65%/35% to estimate their weighted average cost of capital (WACC) (Hart, 1995). "Equity" in this sense is really the over-collected funds obtained by SMUD from their ratepayers to reach the utility-wide DSCR requirements (see Section 2.6.4).

2.6.2 Loan Maturity

Loan maturity (or loan term) is determined at the outset of the lending agreement. Corporate (IOU and public utility) borrowing is frequently done on a continuous roll-over basis. When loans mature, they are replaced with new borrowing that maintains the capital structure. Although such practice is feasible in the corporate-finance situation where lending is not tied to the lifetime of a particular asset, such is not the case in project-finance. In project-finance, the limiting factor is the term of the power purchase agreement.

For U.S. windpower project-finance, Hoffman (1995) and Wong (1995) indicate that 10-15 year maturities are common. A 12 year debt term is assumed in our analysis. Project-finance yearly debt payments include interest and principal.

IOU and public utility bond terms range from a lower limit of a couple years to an upper limit of perhaps 40 years, with principal balloon payments at maturity (typically, only interest is paid on the bonds until maturity). We assume that the maximum debt term (and amortization period) is equivalent to the project analysis period, namely 20 years. For cost assessment purposes, we also assume a yearly principal payment schedule, which is consistent with industry practice (Hart, 1995; Sims, 1995). Project-financed public utility power-plants typically issue a number of bonds with different maturities. In the financial design of the CARES/FloWind project, for example, it was decided to issue bonds with different terms such that principal payments would increase at approximately 4% per year (Wolff, 1995). SMUD's JPA projects also have similarly diverse bond maturities (Central Valley Financing Authority, 1993).

2.6.3 Debt Interest Rate

The interest rate charged depends on both the maturity and risk of the loan. Interest rates typically rise with loan maturity. For publicly traded bonds, such as those issued by investor-owned and public utilities, credit agencies typically rate the loan default risk. Private power projects commonly use project-finance structures that rely on privately-placed debt and bank loans. Although not publicly traded, the same pricing principles apply.

Interest rates vary continuously based on economy-wide considerations. Because we are interested in the comparative financing costs of different forms of ownership, however, the absolute interest rate is less important that the differences among interest rates. Amitz (1995), Karas (1994), Wong (1995), Hoffman (1995), and Kahn (1995) estimate project-financed windpower debt interest rates of 8.5-10.5% for 10-15 year debt terms, with recent domestic projects in the 9-9.5% range. We assume a 9.5% debt interest rate for the private ownership, project-finance scenario.

IOUs finance projects with corporate debt. Interest rates vary depending on maturity, bond credit rating, and general macroeconomic factors. We assume an interest rate of 7.5% for this analysis, which is broadly consistent with recent industry bond issues.

Public entities can avail themselves of significantly lower cost debt due to the tax-exempt nature of the bonds to the holder. One would therefore suspect that tax-exempt bonds would yield interest rates (IRs) that are roughly equivalent to:

Tax exempt bond IR = (1 - marginal tax rate)*(equivalent taxable bond IR)

Recently issued public utility tax-exempt bonds have yielded interest rates in the 5.5%-6.0% range for moderately rated bonds with 25-35 year maturities. We assume a public debt average interest rate of 5.5% for an internally-financed wind project, which is consistent with the rate used in both SMUD (Hart, 1995) and CARES (Wolff, 1995) project assessment calculations.[6]

A public utility project-financed wind facility would likely require a higher interest rate due to the increased investor risk associated with project-finance. For example, Chu (1995) of S&P estimates that a true publicly owned, non-recourse, project-financed natural gas power-plant would require a 50-100 basis point higher interest rate than an internally-financed project of similar type. Assuming a pure non-recourse structure (i.e., no cross-subsidization from the public utility), the "equivalent taxable bond interest rate" might be that for a privately owned, project-financed wind project. Assuming that this rate is 9.5% (from above), and a discount of 20-25%, the project-financed public utility wind project would be expected to require an interest rate of approximately 7.5%.[7]

6 Assuming that the "equivalent taxable bond interest rate" is that for similar maturity IOU bonds, approximately 7.5%, this would imply a marginal tax rate of 0.2-0.25. This is clearly below the 35-40% combined state and federal income tax rate for most corporations, but can likely be explained by the lack of depth in the tax-exempt market.

7 Here we neglect both the term structure of debt and the liquidity differences between privately-placed project-finance debt and publicly traded tax-exempt bonds. These effects are not expected to cancel each other out exactly, and our estimate of the average interest rate should be considered a very rough approximation.

2.6.4 Debt Service Coverage Ratios

To reduce the risk associated with project default, lenders typically require that a project or corporation maintain a minimum ratio of the available cash to total yearly debt service. "Available cash" equals yearly operating income (operating revenues less expenses). Total yearly debt service includes both principal and interest payments. The credit constraint is typically expressed as a minimum acceptable value for the debt service coverage ratio.

Lenders to project-financed windpower facilities typically have stringent project-specific DSCR requirements. Standards for minimum DSCRs fluctuate with time, but can never be below 1.0. If the DSCR is expected to be below the minimum DSCR required by lenders, lenders would demand more equity (and therefore less debt) from the project sponsor. The tendency for developers to maximize debt leverage is limited by the debt service coverage requirements. DSCR constraints typically bind (i.e., DSCR = minimum DSCR requirement) in the first years of operation when revenue streams are at a minimum (due either to escalating energy payments or reduced electric output). Private windpower developers have been able to mitigate the first-year DSCR constraint through several means, including:

(1) Back-loading debt payments; and/or,
(2) Front-loading the power purchase price (e.g., through constant nominal payments).

DSCR requirements have changed with time, and vary substantially by project. A range of 1.3-2.0 is typical for privately owned, project-financed windpower projects (Amitz, 1995; Wong, 1995). Wong (1994) indicates that first-year DSCRs of 1.35-1.40 are currently common, often rising with time if revenue streams are uncertain. For projects with only resource variability, a constant DSCR of 1.4 is a reasonable assumption (Karas, 1994), and this value will be used in our analysis. In our base-case NUG ownership scenario, we also assume that front-loading of the power purchase price is used to mitigate the first-year constraint.

IOUs using corporate-finance are not required to meet specific DSCR requirements for individual projects. However, as noted earlier, the primary restrictive covenant in utility borrowing is a limitation on the issuing of debt beyond certain limits (Smith and Warner, 1979). Maintenance of a particular capital structure therefore effectively acts as a corporate-wide DSCR requirement.

Public utility "corporate" issues of tax-exempt bonds often do contain utility-wide DSCR requirements, but not project-specific ones. For example, SMUD bonds typically require utility-wide yearly debt service coverage ratios of 1.3-1.6. SMUD therefore recovers the extra 30-60% of revenues through electric rates. Because this revenue is not actually required to service the debt, but rather to provide risk assurance to the lenders, it becomes working capital or "ratepayer equity." This "equity" can then be used at SMUD's discretion to invest in new capital projects. The lack of project-specific minimum DSCR requirements in the IOU and public utility internal-finance structures allows individual projects to cross-subsidize others and reduces constraints that are inherent in project-finance.

Lenders to project-financed public utility projects do impose minimum DSCRs. In order to meet these DSCR requirements, SMUD typically provides over-payments in the power purchase rates with their project subsidiaries (JPAs). These over-payments are then returned to SMUD at the end of each year. Although the project itself must meet minimum DSCR requirements, the net effect of the loan covenant on SMUD and its ratepayers is negligible. Since we model the plant from the utility or ratepayer perspective, we do not include a stringent DSCR requirement in the public utility ownership, project-finance scenario.

2.6.5 Debt Principal Payment Schedule

Investor owned and public utilities typically borrow on a roll-over basis. Their primary form of debt is publicly traded bonds, where the principal amount is due entirely upon maturity. When a utility bond matures, it is then replaced by a new bond issue. The principal from the new issue is used to pay off the maturing bond. When analyzing an individual project, however, assumptions on principal repayment must be made. IOUs, in their revenue-requirement assessments, typically assume principal repayment equal to the debt-weighted, straight-line depreciation schedule. Public utility internally-financed project cost estimates are often made assuming mortgage-style debt repayment with equal annual debt payments (including interest and principal) over the life of the project. Although principal payments for project-financed public utility bonds often consist of balloon payments at maturity, project owners typically issue a range of bonds of different terms such that principal is paid throughout the project's life.

By contrast, project-finance privately-placed debt typically involves yearly amortization payments. The shorter the maturity, the greater the up-front burden of these principal payments. Historically, mortgage-style debt repayment, where equal annual total (interest and principal) payments are made, was common. In this scheme, principal payments increase with time and interest payments decrease. Although traditional mortgage-style debt repayment is still used, Hyuck (1995), Wong (1995), and Amitz (1995) indicate that debt payment back-loading has now become relatively common for windpower projects. This form of debt repayment mitigates first-year DSCR constraints, and therefore helps reduce windpower levelized costs.

To simplify the analysis, we assume mortgage-style debt payments. To account for first-year minimum DSCR constraint mitigation, we assume constant nominal (not inflation adjusted) energy payments (front-loading of revenue) rather than back-loading of debt. Approximately half of the recent and planned U.S. windplants use revenue front-loading as a DSCR mitigation approach, and the use of mortgage-style debt repayment simplifies our base-case analysis.

2.6.6 Equity Cost

There is little difference between equity investment in corporate- and project-finance. In both cases, equity represents a residual claim on all surpluses generated by the firm or project. Equity returns come in the form of both direct cash flows and tax shields.

Required equity returns for privately owned, project-financed windpower projects depend on perceived technology and resource risks. Domestic windplant return on equity (ROE) requirements range from a low of 16% (Wong, 1995) to a high of over 20% (Amitz, 1995; Hoffman, 1995). We assume an 18% ROE, typical of recent U.S. windpower projects.

Because IOUs use corporate-finance approaches, a company-wide ROE is typically used when analyzing project economics. This ROE is set by state public utility commissions (PUCs) in rate-cases, and varies with time and by utility. We assume a 12% utility ROE, which is broadly in-line with recent utility experience (EPRI, 1993). The capital structure of public utilities does not typically contain equity in the traditional sense.

2.7 Windpower Project, Cost, Tax, and Operating Assumptions

The windpower project, input cost, and operating assumptions listed here are used consistently in all three of the general models described in Appendix C. We attempt to provide reasonable estimates for both windplant input costs (capital and operating) and operating performance. As noted earlier, tax treatment varies among ownership arrangements. Table 2-1 lists the project, operational, tax, and cost inputs necessary for the financial cash-flow models and the values assumed in our analysis. These assumptions are described in more detail below.

It is important to note that our assumption of input cost equivalence in the three ownership scenarios may not be correct. To the extent that risk is transferred between the parties differently in the three ownership scenarios, these risks may be priced accordingly. For example, if the wind developer provides a utility owner with a fixed-price O&M contract, the risks associated with such a contract are likely to result in higher overall O&M costs. Furthermore, the turbine costs in the utility ownership cases may be higher than in the private ownership scenario due to manufacturer and developer mark-ups. Therefore, the cash-flow analysis results presented in Chapter 3 are likely to provide an upper bound to the cost savings actually available from utility ownership.

Table 2-1. Project, Operating, Cost, and Tax Assumptions

Project Variable	Value	Comments
Project Size	50 MW	Assumed
Capacity Factor	30%	Assumed
Installed Capital Cost ($1996)	$1000/kW	Assumed
O&M Expense ($1997)	$17/kW-yr	Assumed to increase at inflation
Land Expense ($1997)	$190,000/yr	Approximately 3% of total revenue; increases with inflation
Insurance Expense ($1997)	0.15% of installed cost ($75,000/yr)	Assumed to increase with inflation
Administration and Management Fee ($1997)	$50,000/yr	Assumed to increase with inflation
Property Tax Rate and Assessment (IOU and private ownership)	1.1%/yr of book value	Assessment method described below
Production Tax Credit ($1992)	15 mills/kWh	Increases with inflation
Renewable Energy Production Incentive ($1992)	15 mills/kWh	Non-profit analog to the PTC; increases with inflation
Tax Depreciation (IOU and private ownership)	5 yr MACRS (NUG) 7 yr MACRS (IOU) 15 yr MACRS	95% of installed cost 95% of installed cost 5% of installed cost
Effective Income Tax Rate (IOU and private ownership)	38%	Assumed
Inflation Rate	3.5%	Assumed
Nominal Discount Rate	10%	Assumed

PROJECT SIZE: A 50 MW project capacity is assumed, a fairly typical size for a large-scale individual wind farm.

CAPACITY FACTOR: A 30% capacity factor assumes a good wind resource (class 4 or above) and turbine performance. Industry average capacity factors are 20%, reflecting older windpower technology and inferior performance compared to currently available turbines (UWIG, 1991). Recent well-performing facilities reach average levels of 25-30% (OEM, 1995).

INSTALLED CAPITAL COST: Capital costs include all planning, equipment purchase, construction and installation costs for a turnkey wind system, and are claimed by many to have reached levels at or below $1000/kW (UWIG, 1991; Karas, 1994; OEM, 1995;

Conover, 1994). We assume a $1000/kW level in 1996 dollars, although most recent and planned U.S. projects have slightly higher costs (see Table 2-2).

Table 2-2. Windpower Capital Cost Estimates

Project	Estimated Capital Cost ($/kW)	Source
SMUD/Kenetech	1,390 ($1997)	Sheffrin (1994)
CARES/FloWind/BPA	1,150 ($1996)	CARES (1995)
PacifiCorp/Tri-State/PSCo/EWEB/ Kenetech	1,200 ($1996)	Wind Energy Weekly (1995b)
LCRA/Kenetech	1,000 ($1995)	Wind Energy Weekly (1995a)
SCE and NSP/Kenetech	1,220 ($1994)	Kahn (1995)

O&M EXPENSE: We assume O&M costs of $17/kW-yr ($1997), or 6.5 mills/kW, which include: (1) the cost of unscheduled but statistically-predictable routine maintenance; (2) the costs of scheduled preventative maintenance; and, (3) the costs of scheduled major overhauls and subsystem replacements. This is lower than the 9 mill/kWh expected O&M costs listed in OEM (1995), but is roughly consistent (albeit at the low-end) with many published O&M cost estimates (Karas, 1994; Conover, 1994).

LAND EXPENSE: Land leases can be structured in a number of ways, the most common of which is to base lease payments on a percentage of gross revenue. In some cases this percentage increases with time as debt is repaid, and in others the percent payment is constant (Conover, 1996). We assume a constant land lease cost of $190,000/year ($1997) escalating at inflation. This is equivalent to roughly 3% of gross revenue for the private ownership, project-finance base-case scenario. This is consistent with estimates provided by Karas (1994), Conover (1994), and Wong (1995) which indicate a range of 2-5% of electric revenue as a valid and reasonable land lease cost.

INSURANCE EXPENSE: An insurance cost of $75,000/year (0.15% of installed cost), escalating at inflation is assumed. This is higher than estimates in OEM (1995), and lower than those provided by Karas (1994) and Conover (1994), but is generally consistent with industry practice (Wong, 1995).

ADMINISTRATION AND MANAGEMENT FEE: We assume a value of $50,000/year ($1997), escalating at inflation. This is somewhat lower than that estimated by OEM (1995) and Karas (1994), but was validated by Wong (1995).

PROPERTY TAX RATE AND ASSESSMENT: Although we assume a land lease (and therefore land royalty payments), we also assume that project owners pay the property taxes associated with their facilities. Property tax rates and assessment methods vary substantially by state and county. We assume a 1.1% tax rate, which is consistent with California wind project tax rates (OEM, 1995; Wong, 1995). Property tax is typically levied as a percent of the assessed value of a facility, often defined as the book value. Although private entities (IOUs and privately-owned, project-financed wind facilities) must typically pay property taxes on the total value of the facility, public utilities often must only pay property taxes on the unimproved value of the land. This is the case for both the SMUD and CARES projects.

To estimate the taxable value of the land and equipment, both OEM (1994) and Wong (1995) suggest that a 10-year straight-line depreciation schedule for 80% of installed cost is an appropriate assumption for private and IOU facilities. After ten years, facility value is assumed to be constant at 20% of installed cost. This assessment method is similar to that shown in Conover (1994). In the public ownership scenario, we assume a yearly property tax payment of $35,000/year ($1997), escalating with inflation. This is equivalent to a constant assessed value of the unimproved land equal to 6.3% of the facility's total installed cost. This yearly property tax payment is consistent with SMUD estimates of expected property taxes for their 50 MW wind facility (Olmsted, 1995).

PRODUCTION TAX CREDIT: The National Energy Policy Act (EPAct) of 1992 contains several provisions that encourage investment in renewable energy technologies. Specifically, a 15 mill/kWh ($1992) federal production tax credit (PTC) is currently available to private windpower facilities for the first 10 years of project life. The PTC is adjusted for inflation. Unfortunately, not all equity investors have sufficient tax loads to absorb the full tax benefits of the tax credit, especially with alternative minimum tax (AMT) requirements. Hadley, Hill, and Perlack (1993) demonstrate that this can reduce equity returns dramatically. We assume that the PTC is fully absorbed by equity investors in the private and IOU ownership scenarios.

RENEWABLE ENERGY PRODUCTION INCENTIVE: The 15 mill/kWh ($1992) renewable energy production incentive (REPI) is the non-profit analog to the PTC. Because tax credits cannot be used by tax-exempt entities (i.e., public utilities), a similarly sized direct cash payment is provided to non-profit windplant owners. Unlike the PTC, the REPI payments are subject to yearly Congressional budget allocation, and are therefore highly uncertain. Although the PTC has also been subject to recent Congressional attacks, once the first year of the tax credit is obtained, a private investor can be almost certain that the credit will be available for the remaining nine years. This is not the case for the REPI.

TAX DEPRECIATION: Under private ownership, we assume a 5-year modified accelerated cost recovery system (MACRS) for the wind equipment, which uses a 200% declining-balance method, the half year convention, with a switch to the straight-line method in later years. IOU owners of wind equipment typically receive 7-year MACRS (Short *et al*, 1995), and are therefore at a slight disadvantage compared to NUG owners. We assume a

15-year MACRS for the remaining non-wind equipment capital cost, which uses a 150% declining-balance method, half year convention, with a switch to straight-line depreciation in later years. Ninety-five percent of the total installed cost is assumed to be subject to the 5-year (NUG) or 7-year (IOU) depreciation mechanism. This is roughly consistent with Ing (1993).

EFFECTIVE INCOME TAX RATE: We assume a combined state and federal income tax rate of 38%, which is consistent with EPRI (1993).

INFLATION RATE: The post-1995 inflation rate is assumed to be 3.5%.

NOMINAL DISCOUNT RATE: A discount rate is required to normalize the IOU and public utility cash-flows into a levelized nominal rate. Because we are interested in comparing all costs on a consistent basis, we assume a value of 10% for all three scenarios rather than estimating different discount rates for each of the ownership entities. Variations in this value do not substantively alter the results of our analysis.

Total yearly operating costs include general O&M, land expense, insurance, property taxes, and the administration and management fee. Using the values discussed above for these variables, overall operating costs for private ownership of 13 mills/kWh in the first year are calculated. This value is consistent with UWIG (1991), OEM (1995), Conover (1994), and EPRI (1993),which estimate a total operating cost range of 9-14 mills/kWh.

2.8 Cash-Flow Model Descriptions

To model the windpower project cost, tax, operating, and finance variables, we developed three general cash-flow models. In this section, we provide a brief introduction to the techniques used to construct the models (see Appendix C for more detail). In all cases, the spreadsheet models assess an individual fictional 50 MW windpower project based on a 20-year investment life.[8] Costs are evaluated and compared consistently on a nominal 20-year levelized cost basis in 1997 dollars.[9]

The private ownership, project-finance scenario was modeled using a 20-year pro-forma cash-flow model, which tracks revenues, expenses, debt payments, and taxes, and estimates an after-tax net equity cash-flow. This type of financial model is typical of non-utility ownership, and is used in both: (1) computing bid prices; and, (2) financial due diligence. The model

8 In general, the levelized cost of energy is relatively insensitive to changes in the project assessment length. Extending the assessment period from 20 to 30 years, for example, decreases project costs by 2-3 mills/kWh on a nominal levelized basis in all three ownership scenarios analyzed in this report.

9 We often use mills/kWh as the unit for levelized cost comparisons. One mill is equivalent to one-tenth of a cent.

estimates the nominal levelized power purchase price that would be required to meet all cost and financial constraints.

Electric utilities typically proceed through two relatively distinct forms of cost and value analysis when assessing power supply options. The first is primarily a scoping analysis and is used extensively in determining the direct costs of individual power projects. This type of analysis is replicated in this report for IOUs in the form of a traditional 20-year revenue-requirement cash-flow model. The second, more detailed form of analysis, comes only after the initial scoping assessments are complete, and attempts to determine the value of a project through production cost modeling, corporate financial modeling, etc. We ignore this more detailed form of analysis. The revenue-requirement model used in this report was adapted from a model developed by PacifiCorp (Sims, 1995).

We consider two public utility finance arrangements: (1) internal-finance; and, (2) project-finance. Both financial structures were assessed using a 20-year financial cash-flow approach adapted from the model developed by SMUD to assess their Solano windplant (Hart, 1995).

Of course, real-world project and utility analysis procedures are much more sophisticated than those used in this report, but the models developed here do replicate actual assessment procedures quite closely. Our cash-flow models cover most of the relevant costs, but ignore some subtleties such as working capital accounts, debt reserves, construction work in progress ratemaking, etc.

Effects of Ownership and Financing Structure on Windpower Costs

3.1 Overview

In this chapter, we review and analyze the results of the alternative ownership and financing analysis. Using the cash-flow models described in detail in Appendix C, and the windplant cost, tax, operational, and finance variables identified earlier, we conclude that IOU and public utility windplant ownership can result in substantial apparent cost reductions. The most typical form of windplant development, private ownership and project-financing, is found to be up to 40% more costly than alternative utility ownership arrangements. We analyze the driving forces behind the analysis results in Section 3.4, emphasizing capital structure, debt interest rates, debt maturity, minimum DSCR requirements, minimum ROE, property tax reductions, income tax exemptions and assessment methods, the federal production incentive, and the first-year DSCR constraint.

3.2 Summary of Tax and Finance Differences

Table 3-1 lists the key financing and tax differences identified in Chapter 2 among the four ownership and financing scenarios modeled in this report (including public utility project- and internal-finance). These variables are input into the cash-flow models described in Appendix C to estimate a levelized cost of windpower supply.

3.3 Windpower Project Costs Under Various Ownership Structures

The base-case levelized cost results are provided in Table 3-2. These represent the apparent cost of windpower supply under the basic ownership and financing scenarios described in this report. All results are presented as 20-year nominal levelized costs in 1997 dollars.[10] Because capital structure in the private ownership, project-finance structure is assumed to be variable, it is optimized to minimize the levelized cost of energy. Therefore, our private ownership results list not only the levelized cost of energy, but also the capital structure required to obtain this minimum cost. We estimate the cost of public ownership under two scenarios, reflecting the uncertainty associated with the REPI payments. The first assumes full expectation of receiving the 10-year, 15 mill/kWh federal renewable energy production incentive. The second assumes no expectation of receiving any outlays from this program.

10 We list all costs on a levelized *nominal* basis. To convert to real levelized costs, simply multiply the nominal levelized cost by 0.75.

Table 3-1. Key Financing and Cost Differences Among Windpower Ownership Structures

Variable	Private Ownership	IOU Ownership	Public Ownership Internal-Finance	Public Ownership Project-Finance
Capital Structure	Flexible--Can optimize to minimize cost	50% equity 50% debt	100% debt	100% debt
Debt Interest Rate	9.5%	7.5%	5.5%	7.5%
Debt Amortization Period	12 years	20 years	20 years	20 years
Debt Amortization Schedule	Mortgage-Style Repayment	Straight-Line Declining Rate-Base	Mortgage-Style Repayment	Mortgage-Style Repayment
DSCR Requirements	Minimum 1.4	No project-specific requirement	No project-specific requirement	Effectively, no project-specific requirement
Equity Cost	18%	12%	n/a	n/a
Property Tax	Levied on total value of facility	Levied on total value of facility	Levied only on value of land	Levied only on .value of land
Income Tax	Yes, 5-yr Depreciation	Normalized, 7-yr Depreciation	None	None
Production Credit	PTC for 10 years	PTC for 10 years	REPI subject to yearly allocation	REPI subject to yearly allocation

Table 3-2. Effects of Ownership Structure on Windpower Project Cost

Ownership/Financing Scenario	Levelized Cost of Energy (mills/kWh)	% Cost Savings Compared to (1)
(1) Private Ownership, Project-Finance	49.5 (53% equity)	n/a
(2) IOU Ownership, Corporate-Finance	35.3	29%
(3) Public Utility Ownership, Internal-Finance		
a. w/ REPI	28.8	42%
b. w/o REPI	43.5	12%
(4) Public Utility Ownership, Project-Finance		
a. w/ REPI	34.3	31%
b. w/o REPI	48.9	1%

The absolute value of the levelized cost estimates in Table 3-2 are generally consistent with contract prices and estimated windpower costs for recent and planned windplants. For example, the claimed contract prices for the following privately owned facilities are near the

50 mill/kWh cost estimated for the NUG ownership scenario: (1) Kenetech/Lower Colorado River Authority (Bullock, 1995): (2) New World Power/Texas Utilities; (3) Kenetech/Northern States Power (Halet, 1995); and, (4) Kenetech/New England Power/Central Maine Power (Comnes, Belden, and Kahn, 1995). The public ownership cost estimates are also generally consistent with analysis performed by SMUD and CARES for their publicly owned wind projects. CARES estimates that its project (without the REPI payments) will cost approximately 39 mills/kWh on a levelized cost basis (CARES, 1995). SMUD has calculated a life-cycle levelized cost of 43 mills/kWh without the REPI payment, and 34 mills/kWh with the REPI (SMUD, 1995).

Table 3-2 indicates that the apparent financial benefits of IOU and public ownership are substantial compared to the private ownership, project-finance scenario. Under IOU ownership and corporate-finance, the nominal levelized windpower cost is calculated to be 35.3 mills/kWh, approximately 15 mills/kWh less than in the private ownership, project-finance structure.

Assuming 100% expectation of obtaining the 10-year REPI payments, the public ownership, internal-finance scenario is estimated to be the low-cost approach to developing windpower projects (20 mills/kWh less than private NUG ownership). Clearly, the cost savings associated with low-cost debt financing, tax exemptions, and no project-specific DSCR requirements result in substantially lower estimated project costs. Even without the REPI payments, this ownership and financing structure leads to calculated costs that are approximately 6 mills/kWh (12%) less than a privately owned, project-financed windplant. In this "no-REPI payment" scenario, IOU ownership is the lowest cost alternative.

Debt costs are more substantial in the public ownership, project-finance scenario. If REPI payments are included, this ownership and financing scenario still results in substantial cost savings compared to contracting with a private entity to supply windpower. In this case, the calculated nominal levelized cost is approximately equivalent to the IOU ownership scenario, and represents 30% savings compared to a privately owned, project-financed facility. If REPI payments are not included in the cash-flow model, the apparent costs of a project-financed, publicly owned windplant are estimated to be approximately the same as those that would be expected if the utility was to contract for electricity from a private windpower supplier using project-finance.

These results suggest that the most typical form of windplant ownership and finance, namely private ownership and project-financing, is also the most costly type of windpower development of those options considered here. It validates the claims made by utilities considering windpower investments that apparent windpower costs can be reduced through direct utility ownership rather than contracting with NUG windpower suppliers. Using these analysis techniques, our general conclusion is that IOU ownership and finance may be the cheapest form of wind development structure due to the uncertain nature of the public utility REPI payments. Even without the payments, however, the internal-finance public ownership structure is significantly less costly than the private ownership, project-finance scenario. It is also important to note that these estimated utility ownership cost savings may not entirely represent real economies, but may rather be a result of inappropriate analysis techniques. This important issue is considered in Chapter 4.

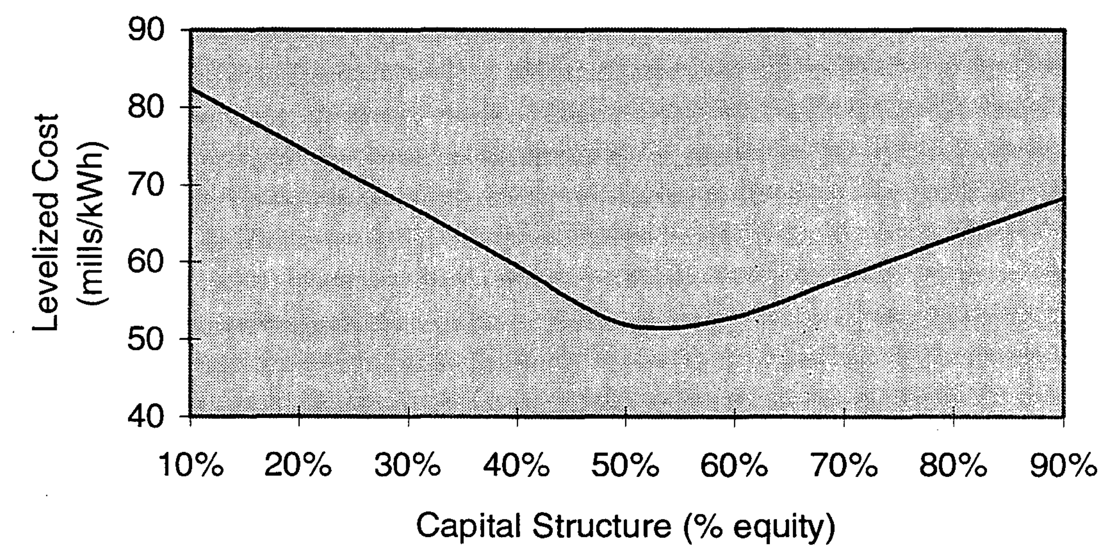
3.4 Analysis of Driving Forces

In this section we consider the driving forces behind the significantly higher costs calculated for privately owned windplants. To determine the relative influence of the various financing and tax input differences among ownership scenarios, we quantitatively estimates the impact of variations in financing variables and terms on the privately owned, project-financed windplant. We conclude that the primary benefits associated with public finance come from the increased level of debt in the capital structure, reduced debt costs, longer debt amortization period, and the lack of project-specific DSCR requirements. The benefits of IOU ownership and finance come primarily from debt and equity cost reductions, longer debt amortization, and the lack of project-specific minimum DSCR requirements. We also assess the nature of the first-year DSCR constraint and possible mitigation approaches for privately owned, project-financed wind projects. We conclude that windpower developers have been relatively successful at mitigating this constraint, resulting in moderate cost reductions. Our utility ownership results, however, are not greatly affected by the DSCR mitigation assumptions.

3.4.1 Capital Structure

Capital structure differs markedly between the three basic types of power project ownership. Debt is generally less costly than equity, so it would seem that the public power 100% debt capital structure has significant advantages over the other ownership arrangements. Because no project-specific DSCR requirements exist from the utility's perspective in the public ownership scenario, increased debt reduces project costs. In general, however, the optimal capital structure will also depend on the relative costs of debt and equity, and on the magnitude of the DSCR constraint. The requirement to meet minimum DSCRs in the private ownership case results in the need for higher-cost equity capital (and therefore a reduction in debt payments). Ignoring the effects of capital structure on debt interest rates and the minimum ROE, Figure 3-1 plots the nominal levelized energy cost for the privately owned windpower facility versus capital structure. As can be seen, the levelized cost of energy is minimized at a capital structure of approximately 50% debt and 50% equity. With higher debt leverage, the power purchase price must increase to meet the DSCR constraint. At higher equity fractions, the cost increases because equity is more costly than debt.

Figure 3-1. Effects of Capital Structure on Windpower Project Cost



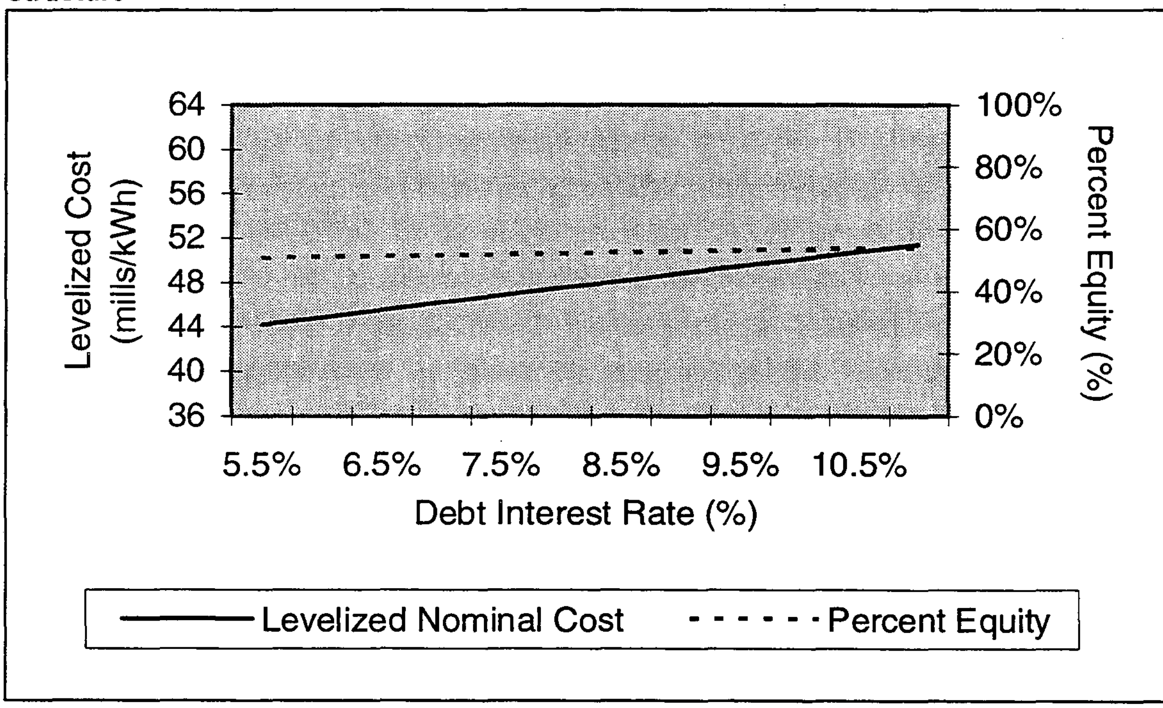
In response to the high debt leveraging seen in the independent power market, many analysts have claimed that NUGs have a financing advantage over utilities, which generally maintain a conservative capital structure with a greater proportion of high-cost equity capital (see, for example, Raboy, 1991). Kahn *et al.* (1992) respond to these claims by suggesting that the financing benefits associated with debt leverage are generally offset by the higher cost of debt and equity capital in the NUG project-finance market. Interestingly, our private ownership, project-finance pro-forma model minimizes levelized cost at a debt-equity ratio consistent with that used by most IOUs (50% debt, 50% equity), not the 80% debt fraction typical of domestic gas- and coal-fired NUG projects. As mentioned in Section 2.6.1, and analyzed in greater depth in Chapter 4, this is almost solely due to the interactive effects of the production tax credit and the need to meet stringent minimum DSCR requirements. These effects limit the financing benefits associated with the capital structure flexibility of privately developed and owned windpower facilities.

3.4.2 Debt Interest Rate

Debt interest rates have a moderate impact on the levelized cost of windpower. To the extent that investor-owned and public utilities use lower debt interest rates than NUGs in project cost calculations, direct utility ownership apparently reduces levelized costs. Figure 3-2 portrays the effects of debt interest rate on the minimum levelized cost of energy from a privately developed, project-financed wind facility, and the optimal capital structure (% equity) needed to obtain this minimum cost.

Holding all else constant, a reduction in the debt interest rate to that typical of recent public utility bond offerings (5.5%) decreases the cost of privately owned windpower by approximately 5 mills/kWh. An interest rate reduction to that used in IOU cost calculations decreases costs by a more modest 3 mills/kWh. As debt costs increase, debt ratios generally decrease only slightly, and optimal capital structure is relatively invariate to interest rate fluctuations. As a testament to the sensitivity of windpower costs to interest rates, the project-finance public ownership scenario results in costs that are 5 mills/kWh higher than the internal-finance structure. From our perspective, the only key financing difference between these two structures is the increased debt interest rate (7.5% versus 5.5%).

Figure 3-2. Effects of Debt Interest Rate on Windpower Project Cost and Optimal Capital Structure

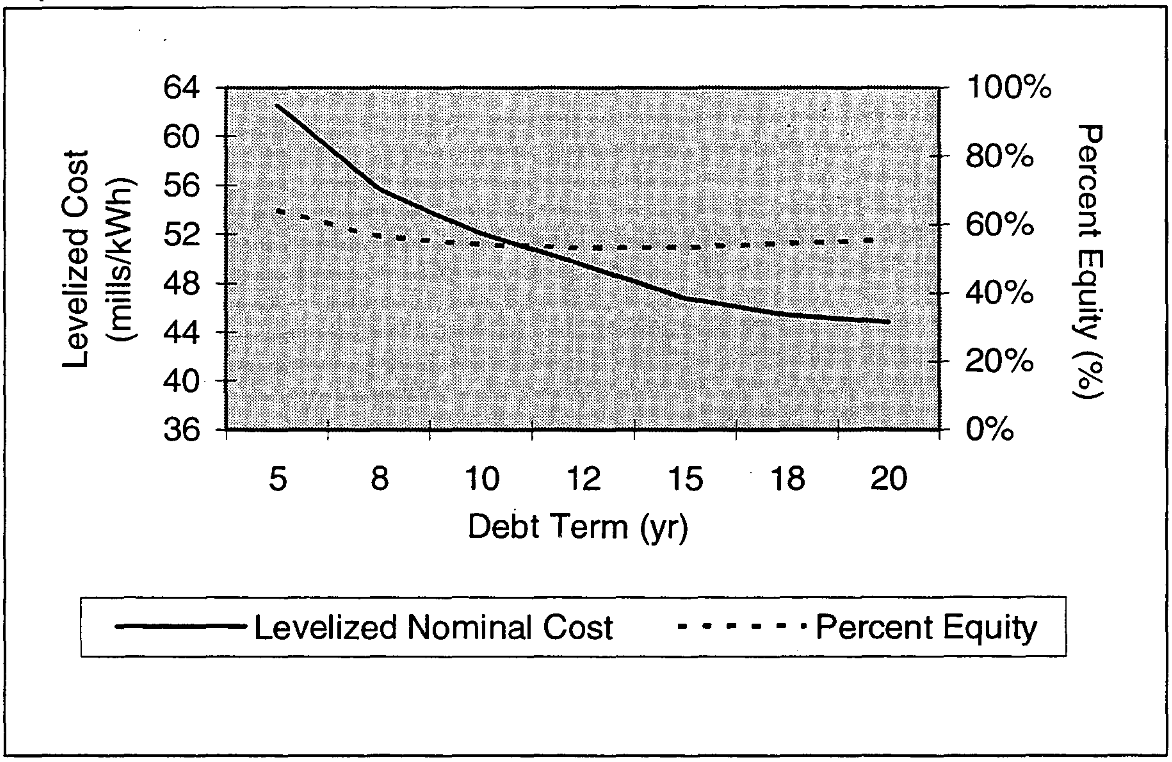


3.4.3 Debt Maturity

Debt maturity has a considerable effect on the apparent levelized cost of windpower. Figure 3-3 illustrates the impact of the debt amortization period on the calculated levelized cost of energy and optimal capital structure for a privately owned facility, ignoring the term structure of interest rates.

Levelized costs are highly dependent on debt term, ranging from a high of 63 mills/kWh for 5-year debt, to a low of 45 mills/kWh for 20-year debt amortization. Holding all else constant, an increase in the amortization period from that typical of project-financed private facilities (12 years) to that used by investor-owned and public utilities (at least 20 years) decreases costs by approximately 5 mills/kWh. Optimal capital structure is somewhat more variable in this case. For shorter amortization periods, the optimal structure becomes biased toward equity capital because the minimum DSCR constraint becomes more binding as yearly debt payments increase.

Figure 3-3. Effects of Debt Amortization Period on Windpower Project Cost and Optimal Capital Structure

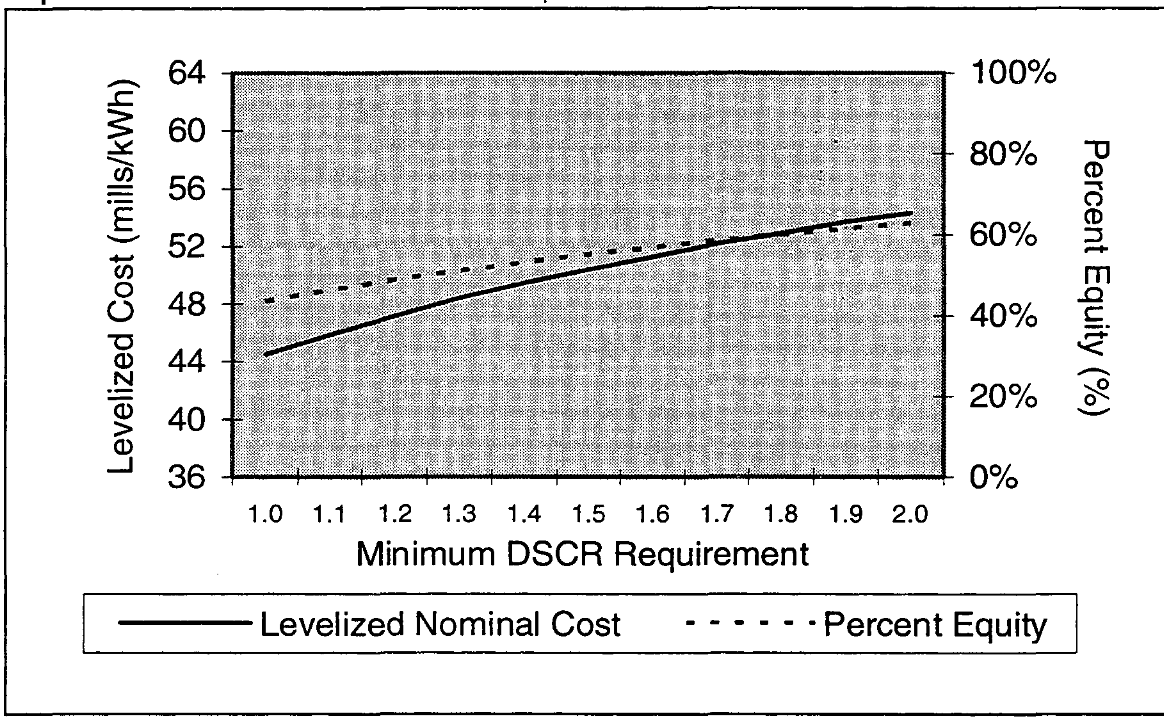


3.4.4 Debt Service Coverage Ratios

Project-specific minimum required DSCRs decrease the amount of debt leverage in the optimal capital structure, and therefore increase levelized cost. We assume in the private ownership, project-finance case that the contract price is constant in nominal dollars, front-loading the revenue stream and mitigating what is usually a *first-year* DSCR constraint. Regardless, the *overall* requirement still has a substantial impact on capital structure and levelized costs. Figure 3-4 illustrates these effects.

The public utility analysis procedure effectively assumes that a DSCR of 1.0 is met each year (see Appendix C). Holding all else constant, if the private ownership, project-finance minimum required DSCR is lowered to 1.0 (from 1.4), levelized costs decrease by approximately 5 mills/kWh. As expected, debt leverage increases as the minimum DSCR requirement decreases.

Figure 3-4. Effects of Overall DSCR Requirements on Windpower Project Cost and Optimal Capital Structure

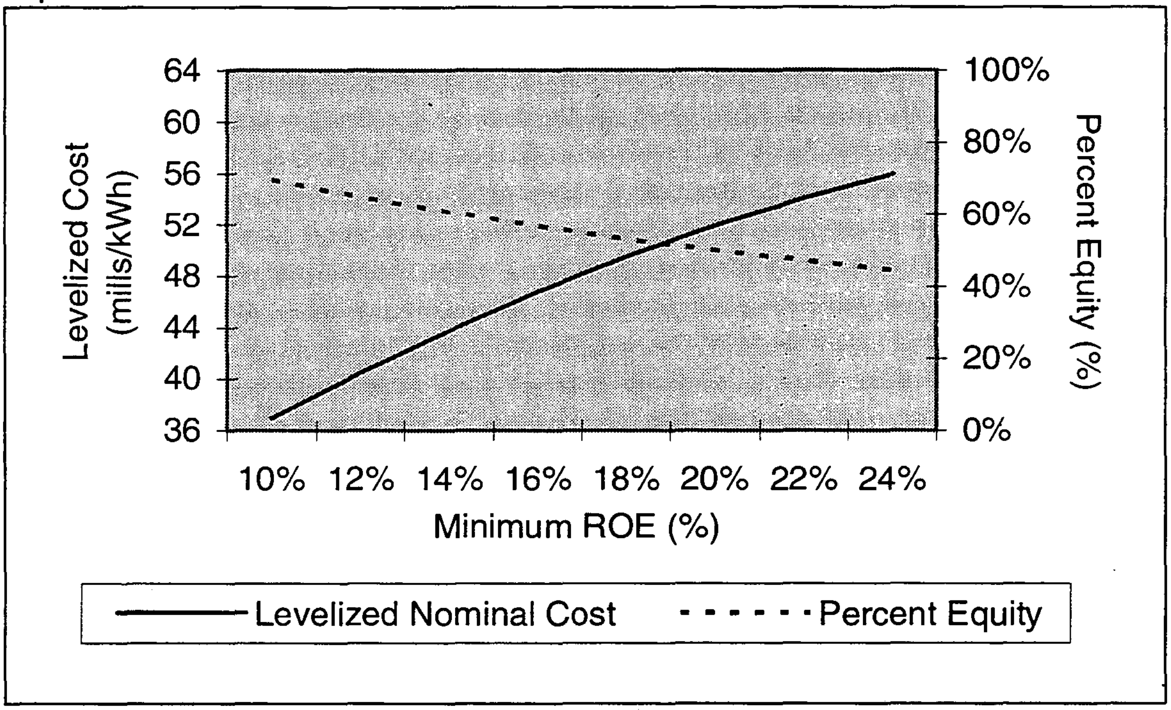


3.4.5 Equity Cost

Of the financial factors considered in this analysis, minimum returns on equity have the most consequential effect on the cost of privately owned and project-financed windpower facilities. Investor-owned utility corporate equity costs are substantially lower than those assumed for privately owned windplants (12% versus 18%), and public utilities do not require high-cost equity. Figure 3-5 shows the impacts of the ROE on the minimum levelized cost of energy from a privately developed, project-financed wind facility, and the optimal capital structure needed to secure this minimum cost.

A reduction in the ROE to that obtainable by IOUs diminishes the estimated cost of privately owned windpower by 9 mills/kWh. Capital structure is also relatively sensitive to changes in the minimum ROE. As expected, lower equity costs result in an increase of the equity fraction in the optimal capital structure.

Figure 3-5. Effects of Minimum Return on Equity on Windpower Project Cost and Optimal Capital Structure



3.4.6 Property Tax Reductions

Public ownership results in reduced property tax payments. This benefit of utility windpower ownership is not as substantial as the financing advantages identified above. Under private NUG ownership, a decrease in property tax payments to that assessed in the public ownership case results in a reduction in the levelized nominal windpower cost to 47.8 mills/kWh, a 3% decrease in cost from the base-case scenario.

3.4.7 Income Tax Exemptions and Depreciation Schedules

Income taxes are assessed differently in all three basic ownership structures. Specifically, public entities do not pay income taxes, IOU taxes are normalized (see Appendix C for a brief description) and 7-year MACRS depreciation is used, and NUG taxes are calculated using a 5-year MACRS depreciation schedule. For a more detailed description of tax normalization and its effects on windpower costs, see Hadley, Hill, and Perlack (1993). These authors conclude that normalization in the IOU scenario decreases levelized windpower costs by approximately 10% because longer tax depreciation lives would be required if flow-through accounting was applied.

To evaluate the cost implications of the IOU 7-year depreciation schedule, we ran the revenue-requirement model under two scenarios: (1) 5-year MACRS; and, (2) 7-year MACRS. Using a 5-year depreciation schedule, IOU levelized costs drop to 34.2 mills/kWh, a 3% reduction from the base-case 7-year MACRS results (35.3 mills/kWh). It is not clear why the IRS suggests different depreciation schedules for different ownership entities, but the cost advantage afforded to private windplant owners from a more rapid depreciation schedule is not substantial.

To evaluate the value of the income tax exemption to public owners of windplants, we calculate the levelized cost of the privately owned, project-financed wind facility assuming that taxes are not paid. In an effort to incrementally analyze different aspects of the ownership results, we assume that the PTC income tax benefits are still usable by the facility owner. Our analysis suggests that an income tax exemption actually raises windpower costs to 55.5 mills/kWh, a 12% increase in levelized costs from the base-case private ownership scenario. The income tax exemption is therefore a moderate disadvantage to public utility ownership of windpower facilities. The advantageous 5-year accelerated depreciation schedule allowed for private windplant owners drives these results by providing income tax benefits (even without the PTC) in the early years of project operation. An income tax exemption actually increases costs by not allowing the project owner to benefit from this advantageous depreciation schedule. It should be noted that this result is *not* reflective of public income tax exemptions in general, and other types of power installations (without such beneficial depreciation schedules) would not exhibit this effect.

3.4.8 Production Incentive

In Chapter 4 we consider the 15 mill/kWh federal PTC and REPI payments in more detail and assess their value in financing and economic analysis. In this section, we examine the relative cost impacts of the REPI payment on estimated public utility windpower costs.

Due to the uncertainty associated with the REPI payments, they cannot be used as security for debt repayment, and are often not included in the assessment of the overall cost of wind facilities. For example neither SMUD nor CARES *relied* on the REPI payments in project cost estimation (Wolff, 1995 and Olmsted, 1995). If these payments were certain, the public ownership, internal-finance structure would provide substantial cost reductions compared to the other ownership scenarios. If not included in the cost assessment, internally financed, publicly owned projects still have considerable cost advantages over private ownership (12%), but would be more costly than IOU owned facilities. Project-financed publicly owned facilities without the REPI payment are expected to cost approximately the same as a private windplant.

3.4.9 Magnitude and Mitigation of the First-Year Debt Service Coverage Ratio Constraint

In Section 3.4.4, we considered the effects of the *overall* level of the minimum DSCR requirement on windpower project costs and optimal capital structure in the private ownership, project-finance scenario. The nature of the *first-year* DSCR constraint and possible mitigation approaches for privately owned, project-financed wind projects are discussed here. It is shown that if the DSCR is relatively constant throughout the debt term at or near the minimum requirement, cost can be reduced from the "unmitigated" first-year DSCR constraint scenario. Our analysis also shows that the first-year DSCR mitigation approach does not fundamentally change our alternative ownership results.

As discussed earlier, developers typically want to maximize debt in the capital structure to reduce financing costs. This tendency is limited by the debt service coverage requirements. Minimum DSCR constraints typically bind in the first couple years of operation when revenue streams are at a minimum, and have historically been a barrier to the absorption of increased levels of low-cost debt. Private windpower developers have been able to control the first-year DSCR constraint through several means. Throughout this report, we have assumed that mitigation is accomplished through front-loading of the energy price by maintaining a constant nominal (not inflation adjusted) price.

Project developers may not always have the ability to front-load payments in this way. Scoring penalties in the bidding process or increased security requirements (Kahn *et al.*, 1990) may be incurred for projects that front-load the payment stream, and some utilities refuse to sign contracts of this type due to the increased risk associated with partially paying for a product before delivery. Recent windpower contracts have seen a mix of terms, but approximately half of these have included escalating energy payments (often at the estimated rate of inflation).

Where front-loading of the revenue stream is impossible or costly, project developers may attempt to back-load the debt payments. Although some banks and institutional lenders still require traditional mortgage-style debt repayment (equal annual total principal and interest payments), a number of institutions now allow total yearly debt payments to more closely track the income stream of the project by back-loading the principal payments (Amitz, 1995; Wong, 1995; Hyuck, 1995). Back-loading of debt payments can be expected to increase the overall debt cost (because it effectively increases the average term of the loan), but the benefits associated with minimum DSCR constraint mitigation typically outweigh the small incremental cost.

In Table 3-3, we list the 12-year DSCR output from the private ownership, project-finance cash-flow model under three scenarios: (1) escalating revenue stream (at inflation) and traditional mortgage-style debt payment; (2) front-loaded revenue stream by using a constant nominal energy price and mortgage-style debt payment (our base-case scenario); and, (3) escalating revenue stream and an "optimal" yearly debt payment scheme. "Optimal" is defined as that debt payment stream that results in a constant yearly DSCR of 1.4, where the minimum DSCR requirement binds throughout the debt term. We also include model output for the 20-year nominal levelized cost of energy and the optimal capital structure.

Table 3-3. First-Year Debt Service Coverage Ratio Constraint

	Debt Service Coverage Ratio		
Year	Escalating Price, Mortgage Debt Payment	Front-Loaded Price, Mortgage Debt Payment (base-case)	Escalating Price, Back-Loaded Debt Payment
1	1.40	1.43	1.40
2	1.47	1.43	1.40
3	1.54	1.43	1.40
4	1.62	1.43	1.40
5	1.69	1.43	1.40
6	1.77	1.43	1.40
7	1.86	1.43	1.40
8	1.94	1.43	1.40
9	2.02	1.42	1.40
10	2.11	1.42	1.40
11	2.20	1.42	1.40
12	2.28	1.40	1.40
Nominal Levelized Cost	56.0 mills/kWh	49.5 mills/kWh	51.6 mills/kWh
Optimal Capital Structure	56% equity	53% equity	55% equity

The first scenario is effectively the "unmitigated" first-year DSCR constraint case. Price escalates at inflation and debt payments are constant throughout the loan, resulting in a high nominal levelized cost of energy and a larger percentage of equity in the capital structure. The minimum DSCR requirement of 1.4 binds strongly in the first year of project operation. The second scenario is the base-case approach used throughout this report, and is characterized by revenue front-loading. The minimum DSCR requirement binds in the final year of operation, but is relatively constant throughout, and therefore the first-year financing constraint is largely mitigated. Compared to the unmitigated constraint scenario, our base-case mitigation approach results in a reduced nominal cost of electricity and allows a slight increase in debt leverage. Finally, the optimal debt back-loading scheme is one in which the DSCR is constant, and the minimum DSCR requirement of 1.4 binds throughout the project debt repayment period. This scenario also reduces the levelized cost of electricity from the unmitigated constraint case, and results in increased debt leverage. It is not entirely clear why this scenario results in higher overall costs than the payment front-loading case, but the choice of discount rate with which to calculate the nominal revenue stream may be the determining factor.

These results lead to the following general conclusions regarding the project-finance first-year DSCR constraint: (1) without mitigation, the first-year DSCR constraint can increase the nominal levelized cost of windpower by approximately 10%; (2) effective developer mitigation measures include front-loading of the revenue stream and/or back-loading of debt repayment; and, (3) both mitigation methods are used extensively in the windpower industry. We also conclude that the private project developer's choice of first-year debt service constraint mitigation does not affect our general conclusion regarding the apparent cost advantages of utility ownership.

CHAPTER 4

Discussion and Policy Implications

4.1 Overview

In this chapter, we describe and analyze some pertinent and policy-related issues associated with the results presented in Chapter 3. Our analysis suggests that at least a portion of the utility-ownership cost savings identified in Chapter 3 come from suboptimal utility analysis techniques rather than true financing advantages. We also briefly discuss the tradeoffs associated with different ownership structures, and emphasize the increased risks involved in utility ownership arrangements. We then consider the federal PTC and REPI payments in more detail and assess their absolute and comparative value in financing and economic analysis. An estimation of the magnitude of the financing premium paid by private windpower developers compared to conventional NUG gas-fired power station financing is also made. This premium, a result of windpower technology and resource risks, is shown to be substantial. Finally, we discuss the potential impact of electric industry restructuring on our alternative ownership results and on windpower finance in general.

4.2 Real versus Perceived Cost Savings

Using traditional utility and private cost-evaluation techniques, we estimated that levelized cost savings of approximately 15-40% (5-20 mills/kWh) might be available through utility ownership and finance as opposed to purchasing windpower from NUG suppliers through PPAs. The economically interesting question is whether utility ownership and self-financing of wind turbine power-plants is really cheaper than power purchases from entities using project-financing or, instead, if utility cost-analysis and implicit subsidies simply conceal the true costs and risks of utility wind ownership. We discuss two aspects of this issue in more detail: (1) the extent to which public utility ownership provides cost savings to the nation as a whole; and, (2) the extent to which IOU ownership provides real cost savings to ratepayers.

Much of the benefit of public ownership comes from the tax-exempt nature of public bonds and the property tax reductions available to public entities. Although these factors may lead to ratepayer cost savings from direct public utility ownership of windpower facilities (instead of purchasing power from independent windpower suppliers), it is unlikely that these savings are being provided to the nation as a whole. In effect, the federal and state governments (through income tax exemptions and allowance for tax-exempt bonds), and the state and local governments (through property tax reductions) subsidize public utility power-project development. The tax revenues that are not collected from activity associated with public utilities must be obtained through other tax mechanisms. To the extent that these taxes are spread over more than just the public utility ratepayers, cross-subsidization of public utility ownership exists.

Another, more narrowly defined question is the extent to which utility ownership provides utility ratepayers *real* cost savings compared to contracting with independent windpower suppliers. Both IOU revenue-requirement and public utility internal-finance cost analysis typically use corporate-wide bond and equity costs and terms. This ignores the variance in risks, and therefore the *marginal* debt and equity costs and terms associated with different types of power facilities. Despite the estimated IOU and public utility cost advantages that come from the use of these assumptions, the risk apparent in project-finance is not entirely eliminated. Due to the tax-exempt nature of public utilities, ownership of wind facilities clearly provides some real cost savings to public utility ratepayers compared to contracting with an independent wind supplier. The real ratepayer savings from IOU ownership are more dubious.

To further explore this issue, we must determine how much of the cost savings are caused by fundamental structural differences between the pro-forma and revenue-requirement models as opposed to variations in the financial input parameters. To do this we use the IOU financial parameters (lower cost debt and equity, longer debt term, rigid capital structure, no DSCR requirement, and 7-year depreciation) in the private ownership, project-finance model. With these financial inputs, the pro-forma model estimates a nominal levelized cost of 32.2 mills/kWh. This is quite close to the 35.3 mills/kWh cost estimated with the revenue-requirement IOU model, and demonstrates that the IOU and NUG cost differential is caused almost solely by the financial inputs, not by fundamental structural model differences.

Because the estimated cost savings associated with IOU ownership come from the assumed financial inputs (not model incompatibilities), the extent to which real cost savings can be achieved depends on the ability of utility ownership to diversify the windpower financial risks away in ways not available to capital markets and NUGs. This diversification would reduce the real financing costs. It is not entirely clear where this risk diversification would come from, but the increased liquidity of publicly traded bonds may provide some real financing advantages over the privately-placed debt typical of private NUG ownership. We make no overall claim on the magnitude of the real cost advantages of IOU ownership, but our analysis suggests that the IOU revenue-requirement cost-estimation approaches are suboptimal in that they ignore risk differences among competing investment choices.

4.3 Rationale and Tradeoffs Among Windpower Ownership Structures

Although this report has emphasized cost savings, there appear to be a number of other secondary reasons that utilities have chosen to pursue windpower ownership rather than purchase power from recent and planned U.S. wind projects. First, many utilities feel that only through direct ownership will they gain experience and understanding of the technology. As wind turbine technology has matured and costs have decreased, utilities have become increasingly interested in gaining first-hand experience with wind turbine installation, operations, and system integration. Second, renewable power project development typically engenders substantial public support, and renewable energy facility ownership has become a means of enhancing public relations for some utilities. Finally, investor-owned utility ownership allows utilities to rate-base a project and earn a return on their investment. Power purchase costs, on the other hand, are typically passed through to ratepayers directly, and shareholder returns are not allowed.

There are also costs to utility ownership of wind facilities. Principally, utility ownership increases utility and ratepayer risk compared to windpower purchases from NUGs. Duvall and Vachon (1994) identify a number of risks related to windpower projects. These include:

(1) installed cost and schedule risk;
(2) wind resource and energy production risk;
(3) wind turbine technology risk;
(4) operation and maintenance risk; and
(5) environmental risks.

The risk of project failure or under-performance lies, in large part, with the utility in utility ownership arrangements. In an arms-length power purchase agreement, performance risk remains with the developer. Contract terms can be developed to minimize utility risk in direct ownership structures. At a cost, turnkey construction contracts, performance guarantees, fixed-price O&M contracts, and other mechanisms can all help mitigate the project risks identified above. These strategies have been used in recent and planned utility wind ownership agreements (Duvall and Vachon, 1994; Olmsted, 1995). We ignore the increased cost of these contract terms in our analysis, suggesting that our results likely provide an upper bound to the apparent cost savings associated with utility ownership. Despite the risk reduction potential of these mechanisms, however, they cannot eliminate all of the risks associated with direct project ownership. Although a quantitative comparison of the risks and rewards of utility ownership is beyond the scope of this report, utilities typically exhibit substantial risk aversion. Olmsted (1995), Afranji (1995), and Duvall (1995) all indicate that a primary factor for SMUD, Portland General Electric (PGE), and PacifiCorp in contract negotiations with wind developers was to reduce utility risk incidence.

A brief description of the processes and decisions made in the SMUD, PGE, and PacifiCorp projects provides useful examples of the multi-variate considerations that are typical of utility decisions to own or purchase power from windplants.

The Sacramento Municipal Utility District issued a general request for proposals (RFP) in 1990 to obtain additional generation resources. Kenetech (then U.S. Windpower), the only windpower developer to bid, responded with a proposal for a 100 MW wind turbine power-plant, the output of which would be sold to SMUD. The project size was later scaled back to 50 MW to reduce perceived system integration difficulties (Olmsted, 1995). Cost was a major impediment to the development of the project, and SMUD decided that ownership of the facility would provide both a reduction in project cost and good public relations for the utility (Olmsted, 1995). To minimize owner-risk, Kenetech was required to provide a turnkey facility with ownership transfer withheld until certification by an independent engineer. To further reduce owner risk, performance guarantees and a fixed-price O&M contract were offered by Kenetech (SMUD, 1995).

The utility-ownership PacifiCorp/PGE/Kenetech project being developed in Eastern Washington was also dominated by project economics. PacifiCorp and PGE representatives indicate that ownership was chosen for three primary reasons: (1) to reduce finance costs (Duvall, 1995; Afranji, 1995); (2) to obtain hands on experience with the technology (Afranji, 1995); and, (3) to earn a shareholder return by rate-basing the utility-owned facility (Sims, 1995). Afranji (1995) indicates that project economics was the dominating factor in PGE's decision, and that analysis suggested cost savings in the "millions" through direct-ownership and self-financing as compared to contracting with an independent windpower supplier through a power purchase agreement. Duvall (1995) also mentions project economics as the dominating decision variable in selecting ownership over a power purchase agreement.

Interestingly, a second PGE wind project, which is being developed by Kenetech in Eastern Oregon, comes in the form of a planned power purchase agreement. Afranji (1995) indicates that the decision to use a PPA arrangement in the second project, rather than direct ownership as in the first, was almost solely due to avian mortality risk. These risks include siting and permitting difficulties, potential public relations complications, and legal issues associated with the U.S. endangered species laws. After the Eastern Washington PacifiCorp/ PGE/Kenetech project experience, the company decided that the risks associated with avian mortality were no longer ones the company wanted to absorb.

4.4 Renewables Production Credit as a Financing and Economic Constraint

In this section, we examine the federal PTC and REPI payments in more detail and evaluate their value in financing and economic analysis. To assess the value of the federal production tax credit for private and IOU ownership, and the equivalent renewable energy production incentive for public entities, the cash-flow models were run with and without the production incentive. Table 4-1 shows the cost estimates for all four ownership scenarios with and without the 10-year incentive in 1997 nominal levelized dollars. We also list the optimal capital structure for private NUG ownership. The public utility cases are simply a replication of the results presented in Section 3.3. In the PTC scenarios, we assume that investors have sufficient tax loads to absorb the full value of the tax credit.[11]

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[11] See Hadley, Hill, and Perlack (1993) for a more detailed description of the effects of the alternative minimum tax on this assumption and on overall wind costs.

Table 4-1. Effects of the Federal PTC and REPI on Nominal Levelized Windpower Costs

Ownership/Financing Scenario	Nominal Levelized Cost of Energy(mills/kWh)	
	With PTC or REPI	Without PTC or REPI
(1) Private Ownership, Project-Finance	49.5 (53% equity)	65.6 (32% equity)
(2) IOU Ownership, Corporate-Finance	35.3	59.0
(3) Public Ownership, Internal-Finance	28.8	43.5
(4) Public Ownership, Project-Finance	34.3	48.9

If the PTC and REPI were repealed, the general conclusion that utility ownership reduces costs would still hold, but by a much smaller margin. If one takes the "no-REPI payment" scenario as the public utility base-case, the repeal altogether of the REPI and PTC programs would enhance the apparent cost savings of public utility ownership under internal- and project-finance scenarios. IOU ownership, while still less costly than the private ownership, project-finance development structure, would be substantially more costly than public ownership.

Several additional issues should be discussed in reference to the results presented in Table 4-1. To structure the discussion, Table 4-2 indicates the primary features and differences between the federal PTC and REPI payments.

Table 4-2. Features of the Federal PTC and REPI

Production Tax Credit	Renewable Energy Production Incentive
10 year, 15 mill/kWh tax credit to private and IOU owners of windpower facilities	10 year, 15 mill/kWh production payment to public owners of windpower facilities
Not subject to yearly budget allocation	Subject to yearly budget allocation
Equity investors may not be able to absorb all of the tax advantages	Can absorb full monetary payment
Disregarding capital structure effects, worth 24 mills/kWh due to cyclic tax advantages	Worth 15 mills/kWh
Not usable to service debt, resulting in capital structure disadvantages to private owners	Usable to service debt

The PTC and REPI were designed so that all owners of windpower facilities would be treated equally by the federal windpower incentive. Our analysis shows, however, that these incentive schemes were not structured in a way to cause this result. First, as discussed earlier, the REPI payment is subject to greater budget uncertainty, and is often not even considered closely in project cost analysis.

Second, to the extent that not all equity investors can absorb the full tax advantages afforded by the federal tax credit, the PTC value is reduced.

Third, the secondary effects associated with receiving the PTC payment alter its value from the 15 mill/kWh direct tax subsidy it was created to provide. By reducing taxes directly, the PTC decreases the revenue required to cover all costs and financing constraints. Reducing revenue decreases taxes further, and the cycle continues.. The ultimate consequence, disregarding capital structure impacts, is that a 15 mill/kWh tax credit is worth approximately 24 mills/kWh (15 mills/kWh ÷ Effective Income Tax Rate). The IOU results in Table 4-1 are reflective of this effect. The nominal levelized cost difference between the PTC and no-PTC scenarios is approximately 24 mills/kWh.

In the private ownership, project-finance structure, the value of the PTC is estimated to be only 16 mills/kWh (i.e., 65.6-49.5 mills/kWh), which is much less than the 24 mill/kWh value received by IOUs. This reduction is due to another secondary effect of the PTC, namely the capital structure impacts explicitly excluded from the above analysis. As indicated by Kahn (1995), a major driving factor behind the capital structure of privately owned and project-financed windpower projects is that the production credit is disbursed as a tax incentive rather than as a direct cash payment. Because a tax credit only benefits equity investors, it is useless for servicing debt and meeting minimum DSCR requirements. Instead, the benefits of the tax credit appear on the tax returns of equity investors, and enhance the equity return of a project. Because the PTC cannot directly help sustain debt or meet minimum DSCR requirements, the optimal capital structure with the credit relies on a greater proportion of higher cost equity than without the credit. Although the credit allows a reduction in contract price (because it helps meet the ROE requirements), if capital structure is unchanged, a decrease in the energy price results in a violation of the minimum DSCR requirement. To combat this problem, the project developer must increase the equity fraction. As Table 4-1 indicates, the optimal capital structure with the credit is 53% equity, 47% debt. Without the credit, our model estimates the optimal capital structure to be 32% equity and 68% debt.[12] It is interesting to note that in overseas markets, where the PTC is unavailable, high debt leverage is still the rule for privately financed projects. In Costa Rica, for example, Kenetech plans to finance a project with 73% debt (Davidson, R., 1996), and a recent financing in Spain by Kenetech consisted of 80% debt.

These results are consistent with Kahn's (1995) analysis, which suggests that bankability of the PTC would result in an incremental debt fraction of 20%, and a decrease in financing cost of 10%. Several windpower project developers are currently considering ways to sell the tax

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12 This is largely consistent with claims made by Wong (1995) that the optimal debt fraction prior to the PTC payments was 70%, but that 50% debt is now common in U.S. project-financed windplants.

credit for cash (Caffyn, 1994; Wong, 1995) but no transactions have been completed. IOUs are immune to this capital structure effect because project-specific minimum DSCRs are not assessed, and capital structure is fixed.

To summarize, it appears that the production incentive is most valuable to IOUs, which can easily absorb the full tax benefits of the credit and are not affected by the secondary capital structure impacts of the PTC. Private owners also receive substantial benefits from the PTC, but its value is reduced by alternative minimum tax restrictions and capital structure effects. Although the REPI payment is immune to the AMT and capital structure impacts, it has been the least valuable due to the budgetary uncertainty of the payments.

4.5 Windpower Costs if Financing Terms Were Comparable to Gas-Fired NUG Projects

In this section, we estimate the financing premium paid by privately owned, project-financed windpower facilities compared to traditional gas-fired NUG power-plants. Due to the risks inherent in the wind turbine technology and resource, and those perceived by the financial community, privately owned and financed windpower facilities typically receive financing that is both more costly and restrictive than is available to more traditional generation sources. Using our pro-forma cash-flow model, we can estimate the magnitude of this cost premium. This analysis is meant to: (1) estimate the magnitude of the cost savings available if windpower financing risks decrease to a level equivalent to current gas-fired generation facilities as wind technology and evaluation methods mature; and (2) evaluate the cost reduction potential of public policies enacted to reduce the financial risks of windpower projects.

A number of authors have alluded to the financing premium paid by renewable energy private power development as compared to gas- and coal-fired NUG projects. Brown (1994) and the IRRC (1992) identify a number of barriers to renewable energy financing. Kahn (1995) estimates the financing premium associated with privately developed and owned wind turbine power-plants compared to gas-fired NUGs. He uses a simplified capital recovery factor (CRF) analysis, and estimates a financing premium of approximately 35-45% for windpower facilities.

We consider the following financing variables in our analysis of wind and gas projects: (1) debt interest rate; (2) debt maturity; (3) minimum DSCR requirements; and, (4) equity cost. Table 4-3 lists our assumptions for these variables in the typical windpower and gas project-financing arrangements. Although the absolute value of these financial variables fluctuate with project-related and macroeconomic factors, the differences between the gas and wind variable estimates were validated from a number of sources. The values listed for the windpower financing scenario are the same as those identified in Chapter 2. The 150 basis point spread between windpower and gas debt costs is within the 80-180 basis point spread suggested by Wong (1995), the 150-300 basis point spread indicated by Amitz (1995), and the 100-150 basis point spread estimated by Hoffman (1995). Gas and wind project debt term is largely a function of the power purchase and fuel contracts. We assume a 3 year spread in term. Wong (1995) suggests a minimum DSCR of 1.2 for gas facilities with at least a 0.2 spread between gas and wind. Amitz (1995) estimates a 1.25 minimum DSCR for gas, with a 0.05-0.15 DSCR premium paid by wind. We assume a 1.25 minimum gas DSCR, with a 0.15 spread between gas and windpower facilities. Equity costs for NUG gas projects are estimated to be 12%, consistent with those reported in Kahn (1995).

Table 4-3. Financing Variable Input Comparisons

Financing Variable	Windpower Project	Gas-fired Project
Debt Interest Rate	9.5%	8.0%
Debt Maturity	12 years	15 years
Minimum DSCR	1.4	1.25
Equity Cost	18%	12%

To estimate the financing premium paid by wind developers, we run the private windpower ownership, project-finance model under two scenarios. The first applies the typical values for wind finance variables, and the second uses the gas financing terms listed in Table 4-3. All other inputs are equivalent, and the PTC is included in both scenarios. The results are provided in Table 4-4. We also list the optimal capital structure in both cases. The actual spread-sheet model run for the gas variable equivalence case is provided in Appendix D.

Table 4-4. Windpower Financing Premium Compared to a NUG Gas-Fired Project

Windpower Financing Scenario		Windpower Nominal Levelized Cost of Energy	% Savings Compared to (1)
(1)	Typical Windpower Project-Financing Terms	49.5 mills/kWh (53% equity)	na
(2)	Gas Project Financing Terms	36.9 mills/kWh (61% equity)	25%

Windpower facilities would be significantly less costly (approximately 1.3 cents/kWh) if the favorable financing terms available to conventional gas-fired projects were also accessible by private windpower owners. Privately owned, project-financed windpower costs would then be roughly comparable to that estimated under utility ownership of current wind turbine power-plants, which already assumes reduced financial risk through low-cost utility capital sources.

Interestingly, the optimal capital structure in the gas variable equivalence case is highly skewed toward equity capital. This is caused by two primary factors. First, because the windplant is being modeled with the PTC, increased debt leverage (which is common in gas projects) is thwarted (see Section 4.4). Second, equity capital in the gas variable scenario is a full 6 percentage points less than in typical windplant financing, reducing the cost of increased equity.

To determine the drivers behind these large financing premium results, we relax each of the windplant financing variables listed in Table 4-3 individually to that typical of gas finance. Table 4-5 shows the effects of these changes on windpower costs and optimal capital structure.

Table 4-5. Driving Forces Behind Windpower Financing Premium Results

Windpower Financing Scenario	Windpower Levelized Cost of Energy	% Savings Compared to (1)
(1) Typical Windpower Project-Financing Terms	49.5 mills/kWh (53% equity)	na
(2) 8% Debt Interest Rate	47.5 mills/kWh (52% equity)	4%
(3) 15 Year Debt Maturity	46.8 mills/kWh (54% equity)	5%
(4) 1.25 Minimum DSCR	47.8 mills/kWh (50% equity)	3%
(5) 12% Minimum ROE	40.5 mills/kWh (65% equity)	18%

The equity cost premium is clearly the dominant factor in the cost and optimal capital structure results. Debt costs and terms are also important in combination, but less so individually.

As the technology matures, resource evaluation becomes more accepted, and information becomes readily available to the financial community, debt and equity costs and terms may become less restrictive and costly for project-financed windpower facilities.[13] If the private ownership, project-finance model continues to be pursued (or is the most promising option post-restructuring) there are a number policies that could be implemented to directly or indirectly reduce finance costs and risks to levels that approach those seen by gas-fired project developers. The creation of long-term contracts and a stable and predictable U.S. wind market would indirectly reduce finance costs by decreasing the market risks of windpower development. More direct mechanisms, such as direct, low-cost, government loans, loan guarantee programs, interest-rate buy-downs, and government-facilitated project-aggregation mechanisms could also be implemented at the state or federal levels to promote investment and reduce financing costs.

13 It is important to note that substantial financing cost reductions have already occurred in the U.S. wind industry. In the mid-1980s, for example, equity returns were expected to be in the 25-30% range (Wong, 1995).

4.6 Electric Industry Restructuring

We would be remiss if we did not briefly discuss the potential effects of electric industry restructuring and deregulation on windpower and our finance results. Electric utility restructuring could fundamentally change the financing of power projects in general, and windpower projects in particular. The ultimate effects of industry restructuring on windpower finance structures and costs is indeterminate at this time, and depends on the eventual market structure and organization as well as the potential adoption of public policies to promote renewables. If merchant plant financing and shorter power purchase contracts become the norm, as many people expect, a greater infusion of equity capital and shorter debt terms might be expected. In comparison to the more traditional generation alternatives, and assuming no additional windpower promotion mechanisms are developed, windpower projects are likely to be more negatively affected by these changing financing regimes. The inherent and perceived technology and resource risks associated with windpower development and the high installed cost of these facilities (relative to gas) both make this technology particularly vulnerable to increased financing costs and restrictions.

Industry restructuring may also affect the relevance of our alternative ownership results. First, industry restructuring has slowed the pace of U.S. wind development substantially, and is at least partly responsible for the financial decline of several prominent wind companies. In response to industry restructuring, a number of U.S. utilities have abandoned or are attempting to renegotiate past utility or regulatory commitments to either own or purchase renewable power technologies. Utilities are frequently apprehensive of commitments that require the purchase or ownership of higher than market-price electric generation sources. If these trends continue, windpower cost reductions will become even more important. Without utility interest in owning or purchasing windpower, however, the relevance of financing costs on renewable energy development is of only moderate significance. Utility reluctance to invest or purchase will be the decisive factor. Second, to the extent that industry structure and regulation is moving away from regulated utility investment in new generation sources, our conclusion that such investment may decrease the levelized cost of windpower is not particularly relevant except in the transition to this new regulatory environment. Finally, to the extent that industry restructuring results in improved utility cost-analysis techniques, utility project assessment procedures may no longer over-estimate the potential cost savings associated with utility ownership of windplants.

The pace and outcome of industry restructuring will vary by state and country, however, and the transition will not be seamless. Furthermore, the U.K. experience with electric industry restructuring demonstrates that industry changes will not necessarily result in a discontinuation of investments in new power facilities by regulated distribution utilities. Utility ownership of power facilities is therefore likely to continue for many more years in some parts of the U.S. Even more importantly, if renewables policies are implemented as part of restructuring decisions, continued renewables investments might be stimulated. Finally, many U.S. state utility commissions have little or no jurisdiction over public utilities.

Although industry restructuring will certainly affect these entities in profound ways, there is no reason to expect a rapid discontinuation of municipal and public ownership of powerplants.

If the private power and project-finance development model continues to dominate the wind industry, and restructuring leads to increased market risk, additional windpower policy mechanisms may be required to sustain the U.S. wind industry. For example, if long-term power market contracts become scarce, there will be substantial need for policies that either: (1) preferentially supply long-term contracts to wind developers (auctioned contracts or renewables portfolio standards, for example); or, (2) provide lender-support so that long-term contracts are less essential (through loan guarantees, for example).

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History of Windpower Finance

U.S. renewable energy development in general, and windpower in particular, was heavily promoted at both the state and federal levels in the late 1970s and early 1980s. State implementation of the Public Utility Regulatory Policies Act (PURPA) of 1978 led to generous utility power purchase contracts in states such as California, and state and federal tax incentives heavily favored renewable energy development. These various incentives led to the rapid growth of the wind industry in California.[14]

During this early period, almost all utility-scale wind development used third-party financing (Williams and Bateman, 1995). The majority of projects were financed through tax-advantaged limited partnership arrangements composed of individual investors, formed to take advantage of the generous tax advantages of windpower facilities. Owners were often more interested in receiving the tax shields provided by the windplants than the power purchase revenues, and the operational performance of early projects was often quite poor. Since the Tax Reform Act of 1986 and other state and federal legislative changes in the mid-1980s, the tax and contract advantages associated with windpower facilities have diminished, and the industry has matured to one that is now characterized by a small number of domestic and international firms with substantially improved operational performance.

Since the mid-1980s, most utility-scale wind energy projects have been developed and financed by private renewable energy companies (privately and publicly held) through project-finance and sale/leaseback arrangements. Sale/leaseback approaches were common in the late-1980s, whereas true project-financed facilities with independent debt and equity investors is now the most frequently used structure. Project debt for renewable energy facilities has typically come from institutional investors, including insurance companies, pension funds, and commercial banks. Equity has either been provided by the project developer or been raised from outside sources. Utility subsidiaries have also become involved, and have provided equity in several recent projects. Active utility subsidiaries include ESI Energy, Inc. (affiliated with Florida Power and Light Co.), and LG&E Power, Inc. (affiliated with LG&E Energy Corporation).

Only recently have U.S. public and investor-owned electric utilities begun to express interest in directly owning and financing their own windplants rather than purchasing windpower from independent non-utility generators.[15] In these arrangements, the project is developed

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14 Windpower incentives included: (1) 10% federal investment tax credit; (2) 15% federal business energy investment tax credit; (3) 5-year accelerated depreciation; (4) 25% California state energy investment tax credit; and, (5) favorable California state power purchase contracts (OTA, 1995).

15 Several utility subsidiaries do have equity stakes in U.S. wind projects, but when discussing direct utility ownership in this report we refer primarily to internal, corporate-financed wind facilities.

and operated by the renewable energy company, but owned by the investor-owned or public utility. See Appendix B for a more detailed description of recent utility activity in windplant ownership.

Electric utility restructuring and deregulation could fundamentally change the financing of power projects in general, and windpower projects in particular. Unfortunately, the ultimate effects of industry restructuring on windpower finance structures and costs is indeterminate and depends of the final outcome of industry restructuring and on the type and magnitude of the remaining renewable energy promotion mechanisms.

Utility Ownership in Recent and Planned Wind Projects

Direct utility involvement in U.S. windpower development has only recently begun, and few large domestic wind projects are currently directly owned and financed by investor-owned or public utilities. Instead, most past and recent wind projects have been financed through limited partnerships, sale/leaseback structures, and private ownership/non-recourse project-finance arrangements.

A number of U.S. utilities have experimented with small (1-5 turbine) installations, but only a few have developed their own large-scale (over 5 MW) wind facilities. Hawaiian Electric Industries was one of the first utilities to become involved with windpower projects in 1985 when it established a non-regulated subsidiary that by 1987 owned approximately 18 MW of installed wind capacity. The Sacramento Municipal Utility District (SMUD) became the first utility to *directly* own and self-finance a large-scale wind project in the United States in 1994, when the first 5 MW phase of a proposed 50 MW project began operation. Under the Utility Wind Turbine Performance Verification Program, Central and South West Corporation (an IOU) now owns a 6 MW project in Texas that began operation in 1995. All other utility-owned projects are of substantially smaller scale. These include projects owned by Green Mountain Power Corp., Marshall Municipal Utilities, Niagara Mohawk Power Corp., Northern States Power Co., Southwestern Public Service Co., Texas Utilities, and Wavery Light and Power (UWIG, 1994; Williams and Bateman, 1995).

Despite a historic lack of interest by utilities to own large-scale windpower facilities, a number of utility-owned and financed projects are currently in the development stage. AWEA (1995) and Renewable Northwest (1995) surveys (updated by the author) indicate that of the approximate 370 MW of wind projects currently in the latter stages of development domestically, 180 MW are utility-owned facilities.[16] Of the utility-owned capacity, four public entities (comprising 90 MW of planned wind capacity) plan to own substantial windpower capacity (over 5 MW each), supported by tax-exempt bonds. These public entities include three municipal utilities, SMUD, Conservation and Renewable Energy Systems (CARES), and the Eugene Water and Electric Board (EWEB) and one cooperative, Tri-State Generation and Transmission Association. Of the remaining utility-owned capacity (90 MW), large investor-owned utility sponsors include PacifiCorp, Portland General Electric (PGE), Public Service Company of Colorado (PSCo), and Green Mountain Power. The IOU-owned projects are to be internally financed through typical corporate-finance structures.

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16 Determining which projects merit a "latter stages of development" heading is somewhat ambiguous. For the purposes of this report, we include those projects listed in the AWEA (1995) publication that have identified a project developer and have a proposed on-line date.

A brief description of the largest direct utility-owned projects operating and in development follows. Information for these descriptions was obtained from AWEA (1995), Renewable Northwest (1995), Olmsted (1995), Duvall (1995), Afranji (1995), and Wolff (1995).[17]

SMUD/KENETECH: SMUD has 5 MW of wind capacity on-line in the Solano Hills of Northern California, and until recently had planned to begin construction on another 45 MW in 1996. Kenetech Windpower, Inc. (Kenetech) is providing project development, equipment manufacturing, construction, and operations and maintenance (O&M) services. The first 5 MW were financed internally by SMUD, and the remaining 45 MW were planned to be financed either through internal funds or through a Joint Powers Authority (JPA) arrangement (project-finance).

PACIFICORP/PGE/KENETECH: Kenetech is currently planning to provide a 31 MW turnkey windpower plant to PGE (40% ownership) and Pacificorp (60% ownership) in Eastern Washington. Kenetech will initially provide O&M services. PGE and PacifiCorp both plan to use internal corporate-finance. The Snohomish County Public Utility District in Washington considered, but rejected, an ownership share in the project.

PACIFICORP/EWEB/TRI-STATE G&T ASSOCIATION/ PSCo/KENETECH: 68 MW of wind capacity is currently being developed by Kenetech in Wyoming. Ownership will be split among four utilities in the following fashion: Pacificorp (37.5 MW), EWEB (10.1 MW), Tri-State Generation and Transmission (10 MW), and PSCo (10.5 MW). PacifiCorp and PSCo plan to use corporate-finance structures, with EWEB and Tri-State using public finance approaches. Kenetech will initially provide O&M services under a 5-year contract.

CARES/FLOWIND/BONNEVILLE POWER ADMINISTRATION: CARES is a joint operating agency that represents 8 Washington Public Utility Districts, and is mandated to develop and own renewable energy and energy efficiency projects for its members. CARES is currently developing a project with FloWind for 25 MW of wind capacity, the output of which will be sold primarily to the Bonneville Power Administration (BPA). FloWind will provide a turnkey wind facility and the initial O&M services. The ownership and financing arrangements of the CARES/BPA facility are perhaps the most innovative of the wind projects under development in the U.S. CARES will technically own the project, and sell most of its output to the BPA, but the BPA is taking a substantial amount of the ownership risk in the windplant. Through a "capability" power purchase contract, the BPA will be contractually bound to CARES to provide nearly all necessary funding for the project regardless of operations performance. The tax-exempt revenue bonds issued by CARES will be backed by the BPA, and the BPA also provided start-up grant funds to CARES.

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17 This description was constructed prior to Kenetech's recent difficulties. Kenetech projects may be slowed or halted altogether by these events.

Description of Financial Cash-Flow Models

C.1 Overview

In this Appendix, we describe the cash-flow models developed to assess the effects of ownership structure and financing on overall utility-scale windpower costs. In Section C.2, we describe the pro-forma cash-flow model used to assess costs in the private ownership, project-financing scenario. The IOU ownership, corporate-finance structure is modeled with a traditional revenue-requirement cash-flow model, characterized in Section C.3. Finally, in Section C.4, the public utility ownership, tax-exempt bond finance cash-flow model is described. In all cases, the spreadsheet models assess an individual fictional 50 MW windpower project based on a 20-year investment life. Costs are evaluated and compared consistently on a nominal 20-year levelized cost basis in 1997 dollars. In all three cash-flow models, dollar amounts are reported in nominal terms.

C.2 Private Ownership, Project-Finance Cash-Flow Model

The project-finance scenario was modeled using a traditional 20-year pro-forma cash-flow model, which tracks revenues, expenses, debt payments, and taxes over a 20-year period and estimates an after-tax net equity cash-flow. This type of financial model is typical in private ownership, project-finance structures, and is used in both: (1) computing bid prices; and, (2) financial due diligence. We calculate the necessary levelized nominal price of energy to meet all cost and financial constraints.[18] The base-case spreadsheet model is included in Figure C-1.

The facility is assumed to be constructed in 1996, with the first year of operations in 1997. The sales price is assumed to be constant in nominal 1997 dollars, and is calculated as the levelized nominal price of energy necessary to meet all cost and financial constraints. Subject to the minimum ROE and DSCR constraints, the nominal energy price (and therefore the utility purchase cost) is minimized by optimizing the debt-equity ratio. The optimal capital structure is provided in the "Financing Assumptions" section of the model, which is then used to calculate the magnitude of debt and equity funds required to finance the installed cost of the facility.

18 This levelized price is equivalent to the levelized cost to the entity purchasing the power (the ratepayer, ultimately), and is calculated to provide a basis for comparison against other ownership and financing scenarios.

Figure C-1. Private Ownership, Project-Finance Base-Case Cash-Flow Model

NUG: WIND PROJECT PRO-FORMA

ASSUMPTIONS	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Installed Capital Cost ($/kW)	1000	($1996)
O&M Expense ($/kW-yr)	17.00	($1997) Increases with inflation
Land Expense ($000s)	190	($1997) Increases with inflation
Insurance (% of installed cost)	0.15%	Assumed; Increases with inflation
Property Tax (% book value)	1.1%	Assumed
Admin. and Mngmt Fee ($000s)	50	($1997) Increases with inflation
Total First Year Operating Cost ($/kWh)	0.013	($1997) Calculated
Effective Income Tax Rate	38.0%	Federal =34%, State=6% (deductable)
Production Tax Credit ($/kWh)	0.015	($1992) Increases with inflation
Inflation Rate (%/yr)	3.5%	Assumed
5 Year Wind Equipment	95.0%	Assumed
15 Year Property	5.0%	Assumed
Discount Rate (nominal)	10.0%	Assumed
Real Discount Rate	6.3%	Calculated
Energy Price Escalation Rate	0.0%	Assumed

RESULTS	Value
Average Debt Service Coverage	1.42
Minimum Debt Service Coverage	1.400
After-Tax IRR on Equity	18.00%
Real Levelized Price ($1997/kWh)	0.0375
Nominal Levelized Price ($1997/kWh)	0.0495
First Year Electricity Price	0.0495

SCENARIO
BASE-CASE

FINANCING ASSUMPTIONS	Fraction	Term	Rate	Notes
Equity Fraction	53.2%	NA	18.00%	Minimum equity return
Debt Fraction	46.8%	12	9.50%	Assumed

PRO-FORMA CASH FLOW

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Output (MWh)		131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Sales Price ($/kWh)		0.049	0.049	0.049	0.049	0.049	0.049	0.049	0.049	0.049	0.049
Operating Revenues ($000)											
Revenues		6498	6498	6498	6498	6498	6498	6498	6498	6498	6498
Operating Expenses ($ 000)											
General O & M Expense		850	880	911	942	975	1010	1045	1081	1119	1158
Land Expense		190	197	204	211	218	226	234	242	250	259
Insurance Expense		75	78	80	83	86	89	92	95	99	102
Property Taxes		550	506	462	418	374	330	286	242	198	154
Administration and Management Fee		50	52	54	55	57	59	61	64	66	68
Total Operating Expenses		1715	1712	1710	1710	1711	1714	1718	1724	1732	1742
Operating Income ($000)		4783	4786	4788	4788	4787	4784	4780	4774	4766	4756
Financing($000)											
Debt Funds	23382										
Equity Funds	26618										
Total Capital Investment	50000										
Cash Available Before Debt		4783	4786	4788	4788	4787	4784	4780	4774	4766	4756
Debt Interest Payment		2221	2114	1997	1869	1728	1574	1406	1221	1019	798
Debt Principal Repayment		1127	1234	1351	1479	1620	1774	1942	2127	2329	2550
Total Debt Payment		3348	3348	3348	3348	3348	3348	3348	3348	3348	3348
Tax Effect on Equity ($000)											
Operating Income		4783	4786	4788	4788	4787	4784	4780	4774	4766	4756
Depreciation (5 yr MACRS)		9500	15200	9120	5472	5472	2736				
Depreciation (15 yr MACRS)		125	238	214	192	173	156	148	148	148	148
Interest Payment		2221	2114	1997	1869	1728	1574	1406	1221	1019	798
Taxable Income		-7063	-12765	-6543	-2745	-2586	318	3227	3405	3599	3811
Income Taxes (w/o PTC)		-2681	-4846	-2484	-1042	-982	121	1225	1293	1366	1447
Production Tax Credit		2341	2423	2508	2595	2686	2780	2878	2978	3083	3190
Tax Savings (Liability)		5022	7269	4991	3637	3668	2659	1653	1686	1716	1744
After Tax Net Equity Cash Flow ($000)	-26618	6457	8707	6431	5078	5107	4096	3085	3112	3134	3152
Pre-Tax Debt Coverage Ratio		1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.42	1.42

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electric Output (MWh)	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Sales Price ($/kWh)	0.049	0.049	0.049	0.049	0.049	0.049	0.049	0.049	0.049	0.049
Operating Revenues ($000)										
Revenues	6498	6498	6498	6498	6498	6498	6498	6498	6498	6498
Operating Expenses ($ 000)										
General O & M Expense	1199	1241	1284	1329	1376	1424	1474	1525	1579	1634
Land Expense	268	277	287	297	308	318	329	341	353	365
Insurance Expense	106	109	113	117	121	126	130	135	139	144
Property Taxes	110	110	110	110	110	110	110	110	110	110
Administration and Management Fee	71	73	76	78	81	84	87	90	93	96
Total Operating Expenses	1753	1811	1870	1932	1996	2062	2130	2201	2274	2350
Operating Income ($000)	4745	4687	4628	4566	4502	4436	4368	4297	4224	4148
Financing($000)										
Debt Funds										
Equity Funds										
Total Capital Investment										
Cash Available Before Debt	4745	4687	4628	4566	4502	4436	4368	4297	4224	4148
Debt Interest Payment	556	290								
Debt Principal Repayment	2792	3058								
Total Debt Payment	3348	3348	0	0	0	0	0	0	0	0
Tax Effect on Equity ($000)										
Operating Income	4745	4687	4628	4566	4502	4436	4368	4297	4224	4148
Depreciation (5 yr MACRS)										
Depreciation (15 yr MACRS)	148	148	148	148	148	74				
Interest Payment	556	290								
Taxable Income	4041	4249	4480	4418	4355	4362	4368	4297	4224	4148
Income Taxes (w/o PTC)	1534	1613	1701	1677	1653	1656	1658	1631	1603	1575
Production Tax Credit										
Tax Savings (Liability)	-1534	-1613	-1701	-1677	-1653	-1656	-1658	-1631	-1603	-1575
After Tax Net Equity Cash Flow ($000)	-137	-274	2927	2889	2849	2780	2710	2666	2621	2574
Pre-Tax Debt Coverage Ratio	1.42	1.40								

Net equity cash-flow equals operating income less debt payments, income tax liabilities, and equity funds. Yearly operating income simply equals the operating revenue (electricity price*electric output) less operating expenses. This value is also equivalent to the "cash available before debt." Total operating expenses include general O&M, land lease, insurance, property taxes, and the administration and management fee. Total combined debt interest and principal payments are constant throughout the base-case 12-year debt term. Interest payments decrease with time, whereas principal payments increase. As defined in the spreadsheet, yearly taxable income equals operating income less tax depreciation and the debt interest expense. Pre-tax-credit income tax equals taxable income multiplied by the effective combined state and federal income tax rate. The PTC reduces the tax liability, and tax savings are typical in the first 10-years of project operation.

The DSCR is calculated as the cash available before debt divided by total debt payments. In our base-case analysis, we assume that the electricity sales price is constant in nominal 1997 dollars, effectively front-loading the contract. This mitigation approach is frequently used by windpower developers.

Note that the after-tax equity cash-flow in this base-case scenario varies substantially throughout the project's 20-year life, even going negative in years 11 and 12. This is due to the limited duration of the tax credit, accelerated depreciation, and a short debt term. In year 11, the production tax credit has expired whereas debt payments continue, resulting in a negative after-tax equity cash-flow (i.e., the taxes associated with the project exceed its before-tax income stream).

C.3 Investor-Owned Utility, Corporate-Finance Cash-Flow Model

To estimate the nominal levelized cost of energy from our hypothetical windplant, the IOU, corporate-finance scenario was modeled using a traditional financial regulatory 20-year revenue-requirement (RR) approach. This model was adapted from the RR model developed by PacifiCorp when analyzing their two planned wind projects in the Northwest (provided by Jamie Sims of PacifiCorp). It is quite representative of actual utility analysis approaches.

Revenue-requirement models must consider ratemaking procedures and tax measures specific to the electric utility industry. Instead of calculating the power purchase price required to service all costs and meet financing constraints, a RR model estimates the yearly revenue that will be required from ratepayers to meet all project costs and provide debt and equity investors a sufficient return on their investments. A nominal levelized energy cost can then be calculated from the yearly required-revenue estimates. Unlike the project-finance scenario, debt-equity ratios are not flexible in the IOU corporate analysis approach, and the debt fraction is assumed to be the corporate average level of approximately 50%. The base-case IOU revenue-requirement model is shown in Figure C-2, and the RR approach is described in more detail below.

Figure C-2. IOU Ownership, Corporate-Finance Base-Case Cash-Flow Model

IOU WIND PROJECT REVENUE REQUIREMENT ANALYSIS

ASSUMPTIONS	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Capital Cost ($/kW)	1000	($1996)
O&M Expense ($/kW-yr)	17.00	($1997) Increases with inflation
Land Expense ($000s)	190	($1997) Increases with inflation
Insurance (% of installed cost)	0.15%	Assumed; Increases with inflation
Property Tax (% book value)	1.1%	Assumed
Admin. and Mngmt Fee ($000s)	50	($1997) Increases with inflation
Total First Year Operating Cost ($/kWh)	0.013	($1997) Calculated
Effective Income Tax Rate	38.0%	Federal =34%, State=6% (deductable)
Production Tax Credit ($/kWh)	0.015	($1992) Increases with inflation
Inflation Rate (%/yr)	3.5%	Assumed
5 Year Wind Equipment	95.0%	Assumed
15 Year Property	5.0%	Assumed
Discount Rate (nominal)	10.0%	Assumed
Real Discount Rate	6.3%	Calculated

RESULTS	Value
Average Debt Service Coverage	n/a
Minimum Debt Service Coverage	n/a
After-Tax IRR on Equity	12.00%
Real Levelized Cost ($1997/kWh)	0.0268
Nominal Levelized Cost ($1997/kWh)	0.0353
First Year Electricity Cost	0.0523

SCENARIO
BASE-CASE

FINANCING ASSUMPTIONS	Fraction	Term	Rate	Notes
Equity Fraction	50.0%	NA	12.00%	Minimum equity return
Debt Fraction	50.0%	20	7.50%	Assumed

REVENUE REQUIREMENT ANALYSIS

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Output (MWh)		131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Cost ($/kWh)		0.052	0.046	0.039	0.034	0.029	0.025	0.020	0.016	0.013	0.010
Operating Expenses ($ 000)											
General O & M Expense		850	880	911	942	975	1010	1045	1081	1119	1158
Land Expense		190	197	204	211	218	226	234	242	250	259
Insurance Expense		75	78	80	83	86	89	92	95	99	102
Property Taxes		550	506	462	418	374	330	286	242	198	154
Administration and Management Fee		50	52	54	55	57	59	61	64	66	68
(1)Total Operating Expenses		1715	1712	1710	1710	1711	1714	1718	1724	1732	1742
Financing($000)											
Debt Funds	25000										
Equity Funds	25000										
Total Capital Investment	50000										
Capital and Tax Revenue Requirement											
Book Depreciation		2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
Accumulated Book Depreciation		2500	5000	7500	10000	12500	15000	17500	20000	22500	25000
Equity Return		2875	2568	2243	1983	1770	1576	1383	1214	1094	997
Interest Expense		1797	1605	1402	1239	1106	985	864	759	684	623
Production Tax Credit		2341	2423	2508	2595	2686	2780	2878	2978	3083	3190
Tax Depreciation (7 yr. MACRS)		6788	11633	8308	5933	4242	4242	4242	2114		
Tax Depreciation (15 yr property)		125	238	214	192	173	156	148	148	148	148
Deferred Income Tax		1675	3557	2286	1376	727	720	717	-91	-893	-893
Accum. Deferred Income Tax		1675	5232	7518	8894	9621	10341	11058	10968	10075	9182
Current Income Tax (w/o PTC)		-1348	-3468	-2448	-1751	-1288	-1457	-1632	-989	-324	-449
Average Rate Base		47912	42796	37375	33044	29493	26269	23050	20237	18229	16622
(2)Total Capital and Tax RR (3+4+5+6)		5157	4338	3474	2751	2128	1544	955	415	-22	-412
(3) Depreciation		2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
(4) Normalized Inc. Tax (w/o PTC)		327	89	-162	-375	-561	-737	-914	-1079	-1217	-1342
(5) Production Tax Credit		-2341	-2423	-2508	-2595	-2686	-2780	-2878	-2978	-3083	-3190
(6) Return on Rate Base		4671	4173	3644	3222	2876	2561	2247	1973	1777	1621
Total Revenue Requirement (000s) (1+2)		6872	6050	5184	4461	3839	3258	2673	2140	1710	1330

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electric Output (MWh)	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Cost ($/kWh)	0.048	0.047	0.045	0.044	0.043	0.042	0.041	0.040	0.039	0.038
Operating Expenses ($ 000)										
General O & M Expense	1199	1241	1284	1329	1376	1424	1474	1525	1579	1634
Land Expense	268	277	287	297	308	318	329	341	353	365
Insurance Expense	106	109	113	117	121	126	130	135	139	144
Property Taxes	110	110	110	110	110	110	110	110	110	110
Administration and Management Fee	71	73	76	78	81	84	87	90	93	96
(1)Total Operating Expenses	1753	1811	1870	1932	1996	2062	2130	2201	2274	2350
Financing($000)										
Debt Funds										
Equity Funds										
Total Capital Investment										
Capital and Tax Revenue Requirement										
Book Depreciation	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
Accumulated Book Depreciation	27500	30000	32500	35000	37500	40000	42500	45000	47500	50000
Equity Return	901	804	708	612	515	420	326	233	140	47
Interest Expense	563	503	443	382	322	262	204	145	87	29
Production Tax Credit										
Tax Depreciation (7 yr. MACRS)										
Tax Depreciation (15 yr property)	148	148	148	148	148	74				
Deferred Income Tax	-893	-893	-893	-893	-893	-921	-949	-949	-949	-949
Accum. Deferred Income Tax	8289	7396	6503	5610	4717	3796	2847	1898	949	0
Current Income Tax (w/o PTC)	1444	1385	1326	1267	1208	1178	1148	1091	1034	977
Average Rate Base	15015	13408	11801	10194	8587	6994	5429	3878	2327	776
(2)Total Capital and Tax RR (3+4+5+6)	4515	4299	4084	3868	3652	3439	3229	3020	2812	2604
(3) Depreciation	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
(4) Normalized Inc. Tax (w/o PTC)	551	492	433	374	315	257	199	142	85	28
(5) Production Tax Credit	0	0	0	0	0	0	0	0	0	0
(6) Return on Rate Base	1464	1307	1151	994	837	682	529	378	227	76
Total Revenue Requirement (000s) (1+2)	6268	6110	5954	5800	5648	5500	5359	5221	5086	4954

To calculate the yearly required-revenue to meet project costs and provide corporate investors a fair rate of return, the typical rate-making formula for IOUs is as follows:

Required Revenue = ***Fuel Costs + Operating Expenses + Normalized Income Taxes + Depreciation + (Rate-Base)*(Allowed Rate of Return)***

As Figure C-2 illustrates, total operating costs include all of the same components as in the private ownership, project-finance scenario, and all operating expense values are comparable between the two models. These costs are simply passed through in the yearly total RR calculation.

Capital and tax revenue-requirements (taxes, depreciation, and return on rate-base) are co-determined, and recursiveness can only be eliminated by simplifying the RR equations. The components of the general capital and tax RR ratemaking formula can be expanded as follows.

RR(capital and tax)= ***Book Depreciation + Equity Return + Interest Expense + Current Income Tax + Deferred Income Tax - Production Tax Credit***

Where: (Rate-Base)*(Allowed Rate of Return) = Equity Return + Interest Expense; and, Normalized Income Tax (w/o PTC) = Current Income Tax + Deferred Income Tax.

A brief description of "normalized income tax" is warranted. Utility ratemaking accounting systems typically differ from tax accounting. Specifically, the MACRS accelerated depreciation system used for tax purposes is not used directly in ratemaking. Whereas private power developers can flow the tax benefits of accelerated depreciation directly to the equity investors in the year they are received, electric utility ratemaking typically requires "normalization" if accelerated depreciation is to be used (Hadley, Hill, and Perlack, 1993). When taxes are normalized, the reductions in "current taxes" due to accelerated depreciation are not passed directly to the ratepayer in the year of their occurrence, but rather are spread over the life of the facility. Customers pay the "deferred income tax" early in the project's life (creating an "accumulated deferred income tax" account), but are refunded in later years, therefore spreading the benefits of accelerated depreciation over the life of the project. These advance payments are also used to lower the amount of rate-base by creating a deferred tax liability, therefore reducing the overall return on rate-base.

A listing of the equations used to estimate the components of the capital and tax RR equation shown above is included in Figure C-3. The spreadsheet model uses these equations, solving for the recursiveness embodied in the "Current Income Tax" account, to determine total annual revenue requirements. Total RR equals the capital and tax RR plus operating expenses. Other entries in the capital and tax RR section of the model are used to determine the various components of the RR.

Figure C-3. IOU Revenue-Requirement Calculations

Book Depreciation = (Total Capital Cost)/(Evaluation Period)

Accumulated Book Depreciation = (Book Depreciation$_i$) + (Accumulated Book Depreciation$_{i-1}$)

Equity Return = (Percent of Equity in Capital Structure) * (ROE) * (Average Rate-Base)

Interest Expense = (Percent Debt in Capital Structure) * (Debt Interest Rate) * (Average Rate-Base)

Deferred Income Tax = (Tax Depreciation - Book Depreciation) * (Effective Income Tax Rate)

Accumulated Deferred Income Tax = (Deferred Income Tax$_i$) + (Accumulated Deferred Income Tax$_{i-1}$)

Current Income Tax (w/o tax credit) = (Total Required Revenue - Operating Expenses - Tax Depreciation - Interest Expense) * (Effective Income Tax Rate)

Average Rate-Base = (Total Capital Cost) - (Accumulated Book Depreciation$_{i-1}$+ Accumulated Deferred Income Tax$_{i-1}$ +Accumulated Book Depreciation$_i$ + Accumulated Deferred Income Tax$_i$)/2

Production Tax Credit = (Tax Credit Rate) * (Annual Electric Generation)

Normalized Income Tax (w/o PTC) = (Current Income Tax) + (Deferred Income Tax)

As can be noted from Figure C-2, the total RR varies substantially from year to year. In fact, the capital and tax RR even goes negative in years 9 and 10. These variations are a result of tax normalization (which affects yearly tax liabilities) and the production tax credit. For a more detailed description of the revenue-requirement methodology, see Hadley, Hill, and Perlack (1993).

The yearly electricity cost is then calculated at the total RR divided by the yearly windplant electric output. In the "Results" section of the model, the real and nominal 20-year levelized energy costs are calculated. The nominal levelized electricity cost is simply that levelized cost, when discounted to 1997, that is equal to the discounted value of the actual cost stream.

C.4 Public Utility Ownership, Tax-Exempt Bond Finance Cash-Flow Model

As with IOUs, when assessing the value of a project, public utilities typically proceed through two forms of analysis. The first is primarily a scoping analysis to determine the direct cost of power supply options, which we replicate in the form of a 20-year cash-flow model.

We discuss two alternative approaches to public utility finance, and thus two different cost assessment approaches: (1) internal-finance cash-flow analysis; and, (2) project-finance cash-flow analysis.

C.4.1 Internal-Finance Cash-Flow Analysis

To estimate the nominal levelized cost of the 50 MW windplant, the public utility, internal-finance scenario was modeled using a traditional 20-year financial cash-flow approach. This simple spreadsheet model was adapted from the model developed by SMUD to assess the Solano windplant (Hart, 1995), and is also quite similar to the analysis approach used by CARES (Wolff, 1995). It is quite representative of actual public utility power project cost assessments.

Similar to the IOU RR model, the public utility ownership model estimates the electricity revenues required to service all operating and debt costs. It does not, however, require as sophisticated an analysis because income taxes are not a factor and equity returns are not present. A 100% tax-exempt debt structure is assumed. The model tracks expenses, debt payments, and REPI payments over the 20-year assessment period, and calculates the yearly electric revenue required to service these requirements. A nominal levelized energy cost can be calculated from the yearly required electric revenue estimates. Figure C-4 shows the base-case internal-finance cash-flow model.

In the public utility, internal-finance analysis approach, the yearly cost of the project to the utility (and therefore the required ratepayer revenue) exactly equals the operating and debt costs less the renewable energy production incentive (if included).

Total Project Costs = Operating Expenses + Debt Payments - Renewable Energy Production Payment

As Figure C-4 illustrates, total operating costs include all of the same components as in the private and IOU ownership scenarios, but not all cost values are equivalent. Specifically, property taxes are significantly reduced under public ownership.

Although tax-exempt bonds are not issued specifically for individual projects, and we can therefore not precisely determine the principal repayment schedule, we assume equal annual total debt payments over the 20-year analysis period. This is consistent with the analysis procedure utilized by SMUD (Hart, 1995). Debt service coverage ratio requirements are not assessed at this level of analysis, but as can be seen from Figure C-4, DSCRs are constant at 1.0 when all costs are assumed to be exactly recovered from rates.

Figure C-4. Public Utility Ownership, Tax-Exempt Bond Finance Base-Case Cash-Flow Model

PUBLIC UTILITY: WIND PROJECT PRO-FORMA

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Installed Capital Cost ($/kW)	1000	($1996)
O&M Expense ($/kW-yr)	17.00	($1997) Increases with inflation
Land Expense ($000s)	190	($1997) Increases with inflation
Insurance (% of installed cost)	0.15%	Assumed; Increases with inflation
Property Tax ($000s)	35	Assumed
Admin. and Mngmt Fee ($000s)	50	($1997) Increases with inflation
Total First Year Operating Cost ($/kWh)	0.009	($1997) Calculated
Production Credit ($/kWh)	0.015	($1992) Increases with inflation
Inflation Rate (%/yr)	3.5%	Assumed
Discount Rate (nominal)	10.0%	Assumed
Real Discount Rate	6.3%	Calculated

RESULTS:	Value
Average Debt Service Coverage	1.00
Minimum Debt Service Coverage	1.00
Real Levelized Cost ($1997/kWh)	0.0218
Nominal Levelized Cost ($1997/kWh)	0.0288
First Year Electricity Cost	0.0232

SCENARIO:
BASE-CASE

FINANCING ASSUMPTIONS:	Fraction	Max Term	Rate	Notes
Debt Fraction	100.0%	20	5.50%	Assumed Average Tax-Exempt Rate

CASH FLOW ANALYSIS:																					
Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electric Output (MWh)		131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Cost ($/kWh)		0.023	0.023	0.023	0.022	0.022	0.022	0.021	0.021	0.020	0.020	0.045	0.045	0.046	0.046	0.047	0.047	0.048	0.048	0.049	0.049
Operating Expenses ($ 000)																					
General O & M Expense		850	880	911	942	975	1010	1045	1081	1119	1158	1199	1241	1284	1329	1376	1424	1474	1525	1579	1634
Land Expense		190	197	204	211	218	226	234	242	250	259	268	277	287	297	308	318	329	341	353	365
Insurance Expense		75	78	80	83	86	89	92	95	99	102	106	109	113	117	121	126	130	135	139	144
Property Taxes		35	36	37	39	40	42	43	45	46	48	49	51	53	55	57	59	61	63	65	67
Administration and Management Fee		50	52	54	55	57	59	61	64	66	68	71	73	76	78	81	84	87	90	93	96
Total Operating Expenses		1200	1242	1285	1330	1377	1425	1475	1527	1580	1635	1693	1752	1813	1877	1942	2010	2081	2154	2229	2307
Financing($000)																					
Debt Funds	50000																				
Total Capital Investment	50000																				
Debt Interest Payment		2750	2671	2588	2500	2408	2310	2207	2098	1983	1862	1735	1600	1458	1308	1150	983	807	621	425	218
Debt Principal Repayment		1434	1513	1596	1684	1776	1874	1977	2086	2201	2322	2449	2584	2726	2876	3034	3201	3377	3563	3759	3966
Total Debt Payment		4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184	4184
Production Incentive ($000s)		2341	2423	2508	2595	2686	2780	2878	2978	3083	3190										
Required Ratepayer Revenue ($000s)		3043	3003	2962	2919	2875	2829	2781	2732	2682	2629	5877	5936	5997	6061	6126	6194	6265	6338	6413	6491
Debt Coverage Ratio		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

C.4.2 Project-Finance Cash-Flow Analysis

The key analytic differences between the public utility internal- and project-finance cash-flow techniques are:

(1) Project-finance debt costs are higher, and should be modeled as such.
(2) Project-financed public utility power-plants typically issue bonds of different maturities so that principal is repaid throughout the expected operating life of the project (not in one balloon payment at the end). However, the actual mix of bond maturities will not generally result in equal annual total debt payments during the investment life as assumed in the internal-finance case.
(3) Minimum debt service coverage ratios are assessed on individual projects in the project-finance case.

We account for the first issue by using the higher public utility project-finance debt cost estimated in Chapter 2. The second issue is slightly more complex because of its project-specificity. We continue to assume mortgage-style debt repayment, where total debt payments are constant over the 20-year analysis period. Although this will not generally be a correct assumption for individual projects, it should provide a reasonable estimate of actual debt payment schemes. Finally, although minimum DSCR requirements are assessed on the ownership entity in a public utility project-finance scenario, we are more interested in modeling the costs of the project from the utility power purchaser or ratepayer perspective. In the SMUD JPA case, the utility purchaser typically overpays the project ownership entity (the JPA) such that yearly DSCR requirements are met. This cash is refunded at year's end, however, so the power purchaser (SMUD, in this case) is not affected greatly by the minimum DSCR requirement.[19] In effect, from SMUD's perspective, the yearly DSCR requirement is therefore 1.0, which is exactly equal to their net outlays to the project. Overall, the only resulting difference between our internal- and project-finance cash-flow models is the increased debt costs in the project-finance scenario.

19 In general, SMUD will be affected slightly by the overpayments. If the JPA invests the cash appropriately, SMUD will actually be refunded the initial cash outlay plus the interest earned on the funds. Depending on the investment scheme, and SMUD's alternative uses for the funds, SMUD can receive either a net gain or a net loss from the overpayments.

Analysis Results of Gas-Project Finance Variable Equivalence

In this Appendix, we present a pro-forma model run for the privately owned, project-financed windplant if finance variables coincide with those typically used for NUG developed, gas-fired power facilities. The results of this analysis are described in Section 4.5. As can be noted from the model output shown on the following page (Figure D-1), the minimum DSCR requirement binds strongly in the last year of the debt term. This last-year constraint is an outgrowth of our assumption of a constant nominal energy price, which has overly front-loaded the contract payments in the gas variable equivalence case. To remedy this effect, we iterate the price escalation rate until a minimum nominal electricity cost is obtained. This model run is shown in Figure D-2, and represents a DSCR constraint mitigation approach. We find that the optimal escalation rate is 0.4%, which results in a slightly reduced levelized nominal cost of 36.5 mills/kWh (from 36.9 mills/kWh in the base-case), and a slightly decreased equity fraction of 59.5% (from 61%).

Figure D-1. Windpower Pro-Forma: Gas Finance Variable Equivalence

NUGs WIND PROJECT PRO-FORMA

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Installed Capital Cost ($/kW)	1000	($1996)
O&M Expense ($/kW-yr)	17.00	($1997) Increases with inflation
Land Expense ($000s)	190	($1997) Increases with inflation
Insurance (% of installed cost)	0.15%	Assumed; Increases with inflation
Property Tax (% book value)	1.1%	Assumed
Admin. and Mngmt Fee ($000s)	50	($1997) Increases with inflation
Total First Year Operating Cost ($/kWh)	0.013	($1997) Calculated
Effective Income Tax Rate	38.0%	Federal =34%, State=6% (deductable)
Production Tax Credit ($/kWh)	0.015	($1992) Increases with inflation
Inflation Rate (%/yr)	3.5%	Assumed
5 Year Wind Equipment	95.0%	Assumed
15 Year Property	5.0%	Assumed
Discount Rate (nominal)	10.0%	Assumed
Real Discount Rate	6.3%	Calculated
Energy Price Escalation Rate	0.0%	Assumed

RESULTS:	Value
Average Debt Service Coverage	1.35
Minimum Debt Service Coverage	1.250
After-Tax IRR on Equity	12.00%
Real Levelized Price ($1997/kWh)	0.0280
Nominal Levelized Price ($1997/kWh)	0.0369
First Year Electricity Price	0.0369

SCENARIO:
GAS VARIABLE EQUIVALENCE

FINANCING ASSUMPTIONS:	Fraction	Term	Rate	Notes
Equity Fraction	61.0%	NA	12.00%	Minimum equity return
Debt Fraction	39.0%	15	8.00%	Assumed

PRO-FORMA CASH FLOW:

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Output (MWh)		131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Sales Price ($/kWh)		0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Operating Revenues ($000)											
Revenues		4845	4845	4845	4845	4845	4845	4845	4845	4845	4845
Operating Expenses ($ 000)											
General O & M Expense		850	880	911	942	975	1010	1045	1081	1119	1158
Land Expense		190	197	204	211	218	226	234	242	250	259
Insurance Expense		75	78	80	83	86	89	92	95	99	102
Property Taxes		550	506	462	418	374	330	286	242	198	154
Administration and Management Fee		50	52	54	55	57	59	61	64	66	68
Total Operating Expenses		1715	1712	1710	1710	1711	1714	1718	1724	1732	1742
Operating Income ($000)		3130	3134	3135	3136	3134	3132	3127	3121	3113	3104
Financing($000)											
Debt Funds	19513										
Equity Funds	30487										
Total Capital Investment	50000										
Cash Available Before Debt		3130	3134	3135	3136	3134	3132	3127	3121	3113	3104
Debt Interest Payment		1561	1504	1441	1374	1302	1224	1139	1048	949	843
Debt Principal Repayment		719	776	838	905	978	1056	1140	1232	1330	1437
Total Debt Payment		2280	2280	2280	2280	2280	2280	2280	2280	2280	2280
Tax Effect on Equity ($000)											
Operating Income		3130	3134	3135	3136	3134	3132	3127	3121	3113	3104
Depreciation (5 yr MACRS)		9500	15200	9120	5472	5472	2736				
Depreciation (15 yr MACRS)		125	238	214	192	173	156	148	148	148	148
Interest Payment		1561	1504	1441	1374	1302	1224	1139	1048	949	843
Taxable Income		-8056	-13807	-7640	-3903	-3813	-984	1840	1925	2016	2113
Income Taxes (w/o PTC)		-3058	-5241	-2900	-1482	-1447	-373	699	731	765	802
Production Tax Credit		2341	2423	2508	2595	2686	2780	2878	2978	3083	3190
Tax Savings (Liability)		5399	7664	5408	4077	4134	3154	2179	2247	2317	2388
After Tax Net Equity Cash Flow ($000)	-30487	6250	8518	6263	4933	4988	4006	3027	3089	3151	3212
Pre-Tax Debt Coverage Ratio		1.37	1.37	1.38	1.38	1.37	1.37	1.37	1.37	1.37	1.36

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electric Output (MWh)	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Sales Price ($/kWh)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Operating Revenues ($000)										
Revenues	4845	4845	4845	4845	4845	4845	4845	4845	4845	4845
Operating Expenses ($ 000)										
General O & M Expense	1199	1241	1284	1329	1376	1424	1474	1525	1579	1634
Land Expense	268	277	287	297	308	318	329	341	353	365
Insurance Expense	106	109	113	117	121	126	130	135	139	144
Property Taxes	110	110	110	110	110	110	110	110	110	110
Administration and Management Fee	71	73	76	78	81	84	87	90	93	96
Total Operating Expenses	1753	1811	1870	1932	1996	2062	2130	2201	2274	2350
Operating Income ($000)	3092	3034	2975	2913	2850	2784	2715	2645	2571	2496
Financing($000)										
Debt Funds										
Equity Funds										
Total Capital Investment										
Cash Available Before Debt	3092	3034	2975	2913	2850	2784	2715	2645	2571	2496
Debt Interest Payment	728	604	470	325	169					
Debt Principal Repayment	1551	1676	1810	1954	2111					
Total Debt Payment	2280	2280	2280	2280	2280	0	0	0	0	0
Tax Effect on Equity ($000)										
Operating Income	3092	3034	2975	2913	2850	2784	2715	2645	2571	2496
Depreciation (5 yr MACRS)										
Depreciation (15 yr MACRS)	148	148	148	148	148	74				
Interest Payment	728	604	470	325	169					
Taxable Income	2216	2283	2357	2440	2533	2710	2715	2645	2571	2496
Income Taxes (w/o PTC)	841	867	895	926	962	1029	1031	1004	976	947
Production Tax Credit										
Tax Savings (Liability)	-841	-867	-895	-926	-962	-1029	-1031	-1004	-976	-947
After Tax Net Equity Cash Flow ($000)	-29	-112	-200	-293	-392	1755	1685	1641	1595	1548
Pre-Tax Debt Coverage Ratio	1.36	1.33	1.31	1.28	1.25					

Figure D-2. Windpower Pro-Forma: Gas Variable Equivalence and Optimal Price Escalation

NUG: WIND PROJECT PRO-FORMA

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Installed Capital Cost ($/kW)	1000	($1996)
O&M Expense ($/kW-yr)	17.00	($1997) Increases with inflation
Land Expense ($000s)	190	($1997) Increases with inflation
Insurance (% of installed cost)	0.15%	Assumed; Increases with inflation
Property Tax (% book value)	1.1%	Assumed
Admin. and Mngmt Fee ($000s)	50	($1997) Increases with inflation
Total First Year Operating Cost ($/kWh)	0.013	($1997) Calculated
Effective Income Tax Rate	38.0%	Federal =34%, State=6% (deductable)
Production Tax Credit ($/kWh)	0.015	($1992) Increases with inflation
Inflation Rate (%/yr)	3.5%	Assumed
5 Year Wind Equipment	95.0%	Assumed
15 Year Property	5.0%	Assumed
Discount Rate (nominal)	10.0%	Assumed
Real Discount Rate	6.3%	Calculated
Energy Price Escalation Rate	0.4%	Assumed

RESULTS:	Value
Average Debt Service Coverage	1.29
Minimum Debt Service Coverage	1.250
After-Tax IRR on Equity	12.00%
Real Levelized Price ($1997/kWh)	0.0278
Nominal Levelized Price ($1997/kWh)	0.0365
First Year Electricity Price	0.0355

SCENARIO:
GAS VARIABLE EQUIVALENCE: Optimal Price Escalation

FINANCING ASSUMPTIONS:	Fraction	Term	Rate	Notes
Equity Fraction	59.5%	NA	12.00%	Minimum equity return
Debt Fraction	40.5%	15	8.00%	Assumed

PRO-FORMA CASH FLOW:

Year	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Electric Output (MWh)		131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Sales Price ($/kWh)		0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.037	0.037	0.037
Operating Revenues ($000)											
Revenues		4670	4689	4709	4728	4748	4768	4788	4808	4828	4848
Operating Expenses ($ 000)											
General O & M Expense		850	880	911	942	975	1010	1045	1081	1119	1158
Land Expense		190	197	204	211	218	226	234	242	250	259
Insurance Expense		75	78	80	83	86	89	92	95	99	102
Property Taxes		550	506	462	418	374	330	286	242	198	154
Administration and Management Fee		50	52	54	55	57	59	61	64	66	68
Total Operating Expenses		1715	1712	1710	1710	1711	1714	1718	1724	1732	1742
Operating Income ($000)		2955	2977	2999	3019	3037	3054	3070	3084	3096	3107
Financing($000)											
Debt Funds	20232										
Equity Funds	29768										
Total Capital Investment	50000										
Cash Available Before Debt		2955	2977	2999	3019	3037	3054	3070	3084	3096	3107
Debt Interest Payment		1619	1559	1495	1425	1350	1269	1181	1087	985	874
Debt Principal Repayment		745	805	869	939	1014	1095	1182	1277	1379	1490
Total Debt Payment		2364	2364	2364	2364	2364	2364	2364	2364	2364	2364
Tax Effect on Equity ($000)											
Operating Income		2955	2977	2999	3019	3037	3054	3070	3084	3096	3107
Depreciation (5 yr MACRS)		9500	15200	9120	5472	5472	2736				
Depreciation (15 yr MACRS)		125	238	214	192	173	156	148	148	148	148
Interest Payment		1619	1559	1495	1425	1350	1269	1181	1087	985	874
Taxable Income		-8289	-14019	-7830	-4071	-3958	-1106	1741	1850	1964	2085
Income Taxes (w/o PTC)		-3146	-5322	-2972	-1545	-1502	-420	661	702	745	791
Production Tax Credit		2341	2423	2508	2595	2686	2780	2878	2978	3083	3190
Tax Savings (Liability)		5487	7744	5480	4141	4189	3200	2217	2276	2337	2399
After Tax Net Equity Cash Flow ($000)	-29768	6078	8358	6115	4796	4862	3891	2923	2996	3069	3142
Pre-Tax Debt Coverage Ratio		1.25	1.26	1.27	1.28	1.28	1.29	1.30	1.30	1.31	1.31

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Electric Output (MWh)	131400	131400	131400	131400	131400	131400	131400	131400	131400	131400
Electricity Sales Price ($/kWh)	0.037	0.037	0.037	0.038	0.038	0.038	0.038	0.038	0.038	0.038
Operating Revenues ($000)										
Revenues	4869	4889	4909	4930	4950	4971	4992	5013	5034	5055
Operating Expenses ($ 000)										
General O & M Expense	1199	1241	1284	1329	1376	1424	1474	1525	1579	1634
Land Expense	268	277	287	297	308	318	329	341	353	365
Insurance Expense	106	109	113	117	121	126	130	135	139	144
Property Taxes	110	110	110	110	110	110	110	110	110	110
Administration and Management Fee	71	73	76	78	81	84	87	90	93	96
Total Operating Expenses	1753	1811	1870	1932	1996	2062	2130	2201	2274	2350
Operating Income ($000)	3115	3078	3039	2998	2955	2909	2862	2812	2760	2705
Cash Available Before Debt	3115	3078	3039	2998	2955	2909	2862	2812	2760	2705
Debt Interest Payment	755	626	487	337	175					
Debt Principal Repayment	1609	1737	1876	2027	2189					
Total Debt Payment	2364	2364	2364	2364	2364	0	0	0	0	0
Tax Effect on Equity ($000)										
Operating Income	3115	3078	3039	2998	2955	2909	2862	2812	2760	2705
Depreciation (5 yr MACRS)										
Depreciation (15 yr MACRS)	148	148	148	148	148	74				
Interest Payment	755	626	487	337	175					
Taxable Income	2213	2304	2404	2513	2632	2836	2862	2812	2760	2705
Income Taxes (w/o PTC)	840	875	913	954	999	1076	1086	1067	1048	1027
Production Tax Credit										
Tax Savings (Liability)	-840	-875	-913	-954	-999	-1076	-1086	-1067	-1048	-1027
After Tax Net Equity Cash Flow ($000)	-88	-160	-237	-320	-408	1833	1775	1745	1712	1678
Pre-Tax Debt Coverage Ratio	1.32	1.30	1.29	1.27	1.25					

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