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Primer: The DOE Wind Energy Program's Approach to Calculating Cost of Energy

July 9, 2005 — July 8, 2006

K. George and T. Schweizer
Princeton Energy Resources International (PERI)
Rockville, Maryland

Subcontract Report
NREL/SR-500-37653
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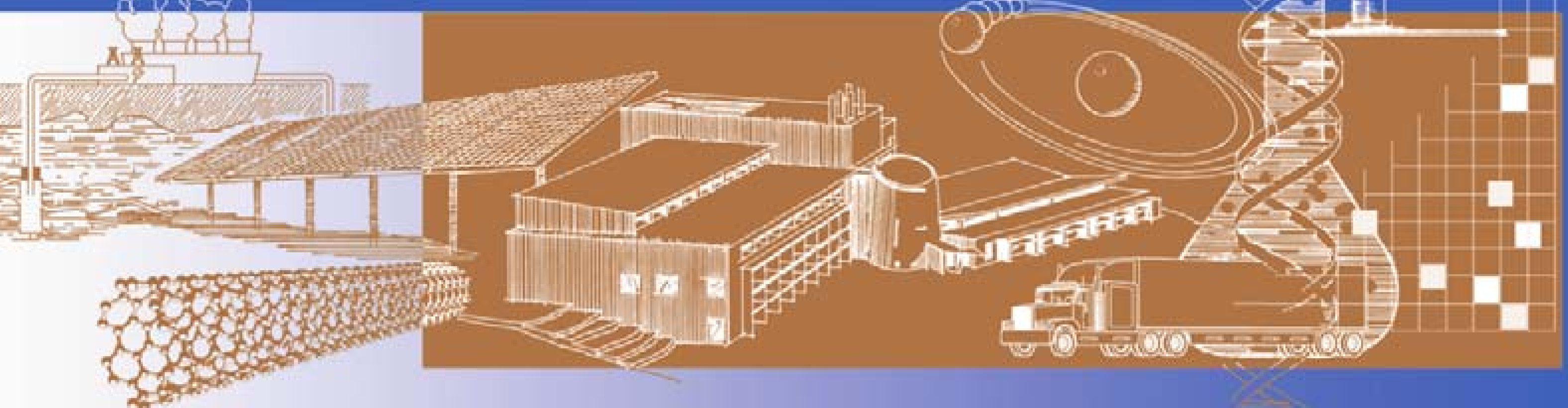

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This work is dedicated to the memory of Dr. Thomas C. Schweizer, who served as president and CEO of PERI until 2005. Tom pioneered many of the evaluation and planning activities for the Wind Energy Program for more than two decades and was recognized as an international expert in renewable energy technology and economics. He earned the DOE's Wind Energy Outstanding Program Leadership Award in 2003.

Executive Summary

This report details the methodology used by the U.S. Department of Energy (DOE) Wind Energy Program and the National Renewable Energy Laboratory (NREL) to calculate levelized cost of energy (COE). To demonstrate application of the methodology, it uses technology and financial assumptions developed for evaluating research and development (R&D) progress for the program's Low-Wind-Speed Technology Project (LWST). This report also demonstrates the variation in COE estimates due to different financing assumptions independent of wind generation technology. This methodology can incorporate changes in project ownership structures, financing approaches, and financial assumptions as they change in the actual market, giving DOE a way to characterize COE relative to current market conditions. COE is an important metric for both renewable energy and fossil-fuel power plants.

COE refers to the plant's wholesale cost of producing electricity. It is calculated from the projected annual revenues the plant would charge to cover capital costs, operating expenses, and return to debt and equity investors, over the years of its contract life.

1.0 Background

When the program uses the term COE, it refers to wholesale prices not retail. It is the cost to deliver power to the utility busbar or substation. The program expresses COE:

- in constant-dollar terms that exclude inflation
- as one levelized value calculated from what may be an uneven series
- excluding the Section 45 Production Tax Credit (PTC) from its calculations, because the PTC is not a permanent part of the Tax Code.

To calculate COE from plant cost and performance data, the program has designed a project cash flow model that projects nominal revenues for the years of contract life and discounts revenues using a nominal discount rate to obtain a nominal net present value (NPV). The analyst running the model then levelizes NPV using a constant-dollar discount rate to obtain one level payment and divides by annual power production.

To calculate discount rates, the program employs the weighted average cost of capital of a typical investor-owned utility (IOU) that would buy power or would produce competitive power. Assuming 2.5% inflation, the nominal discount rate is 8.5% and the constant-dollar rate is 5.85%. The formula for unit constant-dollar levelized cost is [nominal NPV * constant$ rate] / [(1 – (1 + constant$ rate)^(-n)) * (annual energy production)], where n is number of years.

The program further assumes Balance-Sheet Financing by a generating company (GenCo), as will be discussed shortly. This is different than industry, which sometimes talks of a "year one COE" or "bid price," which also may be a wholesale price, but which is the nominal cost per kilowatt-hour (kWh) for power produced during the project's first year, which will escalate, and which includes the PTC. In addition, industry may assume another ownership/finance scenario, such as Independent Power Plant (IPP) Project Finance.

2.0 The Wind Program Approach to Calculating COE

COE is the key measure used to track progress in the DOE Wind Energy Program LWST Project. The President's Management Agenda requires annual reporting of such progress, with the objective of meeting the LWST goal of 3.6 cents/kWh (in 2002 dollars, utilizing the same assumptions as above) in 2012 utilizing Class 4 winds.

The program tracks progress from a baseline, or Reference Turbine, defined as a 1.5-megawatt (MW) turbine installed as part of a 100-MW plant that starts commercial operations in 2003. Table E-1 summarizes project costs by component for such a plant. The turbine system costs include control and electrical systems; shipping costs; warranty costs; and mark-up, including profit and overhead. Balance-of-station costs include wind resource assessment and feasibility studies; surveying; site preparation, including roads, grading and fences; electrical collection system infrastructure; substation; turbine foundations; operation and maintenance (O&M) facilities and equipment; installation and startup; wind plant control and monitoring equipment; spare parts inventory; permits and licenses; legal counsel; project management and engineering; construction insurance; and construction contingency.

As shown in Table E-1, after turbine and balance-of-station costs, the program adds manufacturing uncertainty, which is the manufacturer's mark-up or profit margin. These cost components sum to yield an initial overnight capital cost of $981/kilowatt (kW) in 2002 dollars. Note that although some industry observers consider wind studies, permits, etc. to be "soft costs," i.e., not part of the overnight project cost, they are classed with balance-of-station costs in this analysis.

The program adds construction financing and fees as soft costs to set forth complete costs for the Reference Turbine 100-MW Wind Energy Plant. As shown in Table E-1, GenCo ownership and finance soft costs include interest during construction and home office overhead (at 1% of hardware cost) to cover financing and legal expense. Total loaded capital cost is $1,041/kW. Again, this is for a plant assumed to begin commercial operations in 2003, and it relies on different cost and performance assumptions than one might use today.

Table E-1. Total Loaded Cost for 1.5-MW Reference Turbine in a 100-MW Wind Plant (2002 dollars)

Component	Cost ($1000)	Cost ($/kW)	Cost ($1000)	Cost ($/kW)
	GenCo Balance Sheet		**Project (IPP) Finance (informal only)**	
Turbine Capital Cost	921	614	921	614
Balance-of-Station Cost	388	259	388	259
Manufacturing Uncertainty	162	108	162	108
Initial Overnight Capital Cost	**1,472**	**981**	**1,472**	**981**
Construction Loan Interest	74	50	75	50
GenCo Home Office Overhead (1%)	15	10	--	--
Debt Financing Fees (2% of debt)	--	--	23	15
Equity Financing Fees (3% of equity)	--	--	15	10
Debt Service Reserve (6 months)	--	--	64	43
Total Loaded Cost	**1,561**	**1,041**	**1,649**	**1,099**

In addition to the GenCo case, the program occasionally performs an informal set of calculations assuming ownership and financing on a Project Finance basis by an Independent Power Producer (IPP). As shown in Table E-1, IPP costs include specific debt and equity financing fees and a debt service reserve, for a total loaded cost of $1,099/kW.

Under these assumptions, a capacity factor of 33.8% is used for those conditions. Wind resource conditions for the Reference Turbine are assumed to be a wind Class 4 site at sea level with an annual average wind speed of 5.8 meters per second (m/sec) at 10 m above ground, using a Rayleigh distribution and a wind shear exponent of 0.14. The 100-MW plant starts up in 2003 and produces 296 million kWh/year. Annual operating expenses are estimated as shown in Table E-2.

Table E-2. Annual Operating Expenses for the 1.5-MW Reference Turbine in a 100-MW Wind Plant (2002 dollars)

Component	Cost/turbine (2002$/yr)	Cost/kW (2002$/kW/yr) and escalation
Inflation	2.5%	
Operations and Maintenance	30,000	20.00, by inflation
Site Owner Land Rent (or Royalty)	5,000	3.33, by inflation
Property Tax	15,607	10.40, flat
Insurance	15,607	10.40, by inflation
Major Maintenance & Overhauls	16,000	10.70, flat

The program assumed use of the GenCo financial structure in calculating Reference Turbine COE. The program stipulated that LWST subcontractors would perform COE calculations using a methodology supplied by the program reflecting financing conditions in autumn 2001 and calibrated to GenCo ownership (see Appendix A).

The choice of financial structure selected by the program to characterize wind energy projects has evolved as the industry has matured and reacted to regulatory and market changes. Specifically, following the energy crises of the 1970s, Congress enacted the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPACT), both of which increased competition in electric generation. In 2005, Public Utility Holding Company Act (PUHCA) of 1935 was repealed.

Project (IPP) Finance: Early private power producers, building renewable energy and cogeneration plants, tended to employ a high fraction of debt. They used debt and equity that was non-recourse to the developer/owner and was secured only by the project. Some developers brought in outside equity investors who were in the highest tax brackets to fully utilize a project's tax benefits (e.g., rapid 5-year depreciation, tax credits).

Because wind projects were largely being constructed by IPPs using Project Finance, the program initially used Project (IPP) Finance. It assumed a 30-year life, 40% combined federal and state tax rate, and revenues that escalate 0.5% slower than inflation. It further assumed 70% debt to 30% equity, and 15-year debt with an interest rate of 7%. Target after-tax equity internal rate of return (IRR) was 17% (but could be higher). Requirements for debt coverage (defined as annual operating income versus annual debt payment composed of both interest and principal) were 1.5 times minimum and 1.8 times average

Balance-Sheet (GenCo) Finance: As the wind energy industry matured and the power market shifted toward competitive procurement, the program looked to alternatives to the highly leveraged, high-cost IPP structure. Traditional IOUs built power plants that were financed with general corporate debt and equity by a large corporation with a good reputation and an on-going business. Traditional IOUs owned power plants out-right. Industry observers expected that larger energy developers or generating companies would come to employ Balance-Sheet Finance.

The program has used this GenCo approach to estimate COE since 1997. In the DOE/EPRI book, *Renewable Energy Technology Characterizations* (EPRI TR-109496), dated December 1997, plant cost and performance for wind energy and other renewable energy technologies were forecast from the present to year 2030. GenCo ownership and financing assumptions were employed to present standardized results.

In 1997, the program defined GenCo plant financing to include a 30-year life, 40% combined federal and state tax rate, and revenue escalation 0.5% slower than inflation. It assumed the long-term capital ratio of a mature company is 35% debt to 65% equity. It assumed a wind project is built at a BBB-rated level of financial standards (whether it is actually rated or not) by a Better Business Bureau (BBB)-rated company, where BBB is the lowest investment grade. Given a 30-year life, it assumed a 28-year debt. By late 2001, the program assumed an inflation rate of 2.5% and an interest rate of 6.5% for the LWST Reference Turbine,. Target after-tax equity IRR is 13%. Debt coverage is not a requirement for lenders that are secured by corporate assets, but executive management wants projects with minimum coverage of 1.3 times.

Under all of those assumptions, the COE of the LWST Reference Turbine using GenCo assumptions was estimated to be 4.8 cents/kWh (levelized in constant 2002 dollars). As a point of comparison, the Project (IPP) Finance COE is 5.3 cents/kWh (levelized in constant 2002 dollars).

3.0 Alternative Approaches to Estimating COE

Two other approaches to wind energy plant financing that have emerged recently (after the 2002 LWST Reference Turbine was established) are Portfolio Finance and All-Equity Finance. Portfolio Finance may be undertaken by large energy companies that pool a group of wind energy plants to permanently finance them. Risk is reduced if the portfolio is diversified. The portfolio may be diversified by using (1) different wind turbine technologies, (2) geographically-dispersed independent wind regimes, and (3) different power purchasers in different parts of the country subject to different regional economic pressures.

All-Equity Finance is employed when a developer sells a large share of the project to passive equity institutional investors that seek tax benefits in their investments and have been attracted to wind's 5-year depreciation and 10-year Section 45 PTC. Paying taxes in the highest bracket, they include corporate investors, insurance companies making certain investments, high net worth individuals, etc. These tax-driven passive equity investors are concerned that, in the event of default, the lender will seize assets and equity investors not only lose their investment and prospect of future gains, but face recapture of tax benefits related to partnership capital accounts. The project avoids any chance of default if it assumes no debt. Because risk is reduced with no debt, the equity return can be lower, ranging from about 8% to 13%.

4.0 Updated Assumptions for Financing Structures Reflecting 2004 Business Conditions

As discussed, LWST efforts calculated the Reference Turbine COE estimate in 2002, reflecting a 2002 wind turbine and financial market conditions in October 2001. Since that time, the program updated various assumptions to match economic conditions and industry practices as of 2005. Key changes were: (1) hardware costs are increased; (2) project life is set as 20 years (not 30 years); and (3) GenCo debt is 18 years. Other factors remain about the same, and formal COEs continue to be run without the Section 45 PTC. Costs are specified in year 2004 dollars and the plant starts up in 2005.

In 2005, after reviewing 2005 market costs for wind projects and discussing costs with many industry members, the DOE Wind Energy Program added a "market adjustment" of $200/kW to turbine cost, or $20 million per 100-MW plant. This market adjustment reflects many factors, including increases in the cost of steel and manufacturing processes and cost adders due to tight current market conditions caused by tight manufacturing capacity for turbines, high demand worldwide, rising raw material prices, and temporary exchange rate imbalances. In addition, balance-of-station costs are increased to reflect higher costs for permitting, environmental studies, etc., at $18.86/kW or $1.886 million for a 100-MW wind plant. Balance-of-station cost is further increased by construction contingency, also termed the developer's fee, which is estimated at 5% of hardware costs, which is $60/kW or $6.00 million for the 100-MW plant.

Information for Tables E-3 and E-4 below was gathered during the spring and summer of 2005. It reflects a 100-MW wind energy plant built during 2004 that started up in January 2005. As Table E-3 shows, initial overnight capital cost for GenCo ownership is $1,260/kW or $126.00 million for the entire plant. After adding soft costs for construction financing and financing fees, the total loaded cost for GenCo ownership is $1,332/kW or $133.2 million. Informal calculations show the IPP's total loaded cost is $140.65 million.

Table E-3. Updated Total Loaded Cost for a 100-MW Wind Plant Under 2004 Business Conditions (2004 dollars)

Component	**Cost ($1000)**	**Cost ($1000)**
	GenCo Balance Sheet	Project (IPP) Finance
Turbine Capital Cost	81,420	81,420
Balance-of-Station Cost	27,780	27,780
Manufacturing Uncertainty	10,800	10,800
Construction Contingency	6,000	6,000
Initial Overnight Capital Cost	**126,000**	**126,000**
Construction Loan Interest	6,000	6,000
GenCo Home Office Overhead (1%)	1,200	--
Debt Financing Fees (2% of debt)	--	1,970
Equity Financing Fees (3% of equity)	--	1,270
Debt Service Reserve (6 months)	--	5,410
Total Loaded Cost	**133,200**	**140,650**

Performance remains the same, with a capacity factor of 33.8%. Operating expense did not change much from figures in Table E-2 to figures in Table E-4, with the exception of major maintenance, which is $5/kW and escalates.

Table E-4. Annual Operating Expenses for a 100-MW Wind Plant (2005 dollars)

Component	**Cost ($1,000 in 2005$)**	**Cost/kW ($/kW/yr in 2005$)**
Inflation	2.5%	
Operations and Maintenance	2,067	20.67, by inflation
Site Owner Land Rent (or Royalty)	333	3.33, by inflation
Property Tax	1,332	13.32, flat
Insurance	1,365	13.65, by inflation
Major Maintenance & Overhauls	500	5.00, by inflation

For financing assumptions, the program assumes a 20-year project life, 40% combined tax rate, and GenCo ownership/finance, with no Section 45 PTC. On an informal basis and for special cases, the program will utilize other ownership/financing structures.

For this study, it is assumed that inflation is 2.5%, the yield curve is flat, 10-year Treasuries are 5.5%, and spreads are 100 basis points for BBB-rated GenCo and Portfolio Finance debt and 150 basis points for IPP. One basis point is 1/100 of one percent. However, financing assumptions may be summarized as: GenCo debt is 35% of capital, at 6.5% for 18 years; Portfolio Finance debt is 50% at 6.5% for 15 years; and IPP debt excluding PTC is 70% at 7% for 15 years. Debt coverage standards are: 1.3 times minimum GenCo; 1.6 times minimum and 2 times average with some good PPAs for portfolios; and 1.5 times minimum and 1.8 times average for IPP. Target equity returns are 13% GenCo, 13% Portfolio Finance, 17% IPP, and 11% All Equity.

Furthermore, although formal analysis by the program excludes the Section 45 PTC because it is not permanent, on an informal basis, cash flow analysis sometimes includes the PTC. There are two PTC efforts; one for which the PTC does not aid in debt coverage and a second more aggressive accounting effort where a "monetized" PTC is guaranteed to be paid in cash by a large, credit-worthy company to equity investors that agree to pay the lender, thus aiding debt coverage. When IPP projects take the PTC, their debt fraction is reduced to 60% at 7.0% interest for 15 years. Table E-5 shows the COE results.

Table E-5. Cost of Energy Results for 100-MW Wind Plant reflecting 2004 Business Conditions under Different Ownership/Financing Structures (levelized in 2004 dollars, as cents/kWh)

	Project (IPP) Finance	Balance Sheet (GenCo)	Portfolio Finance	All-Equity
COE with no PTC	6.9	6.4	6.2	7.2
COE with PTC (but no assistance for debt coverage)	6.2	4.3	5.7	5.1
COE with monetized PTC	4.9	4.3	4.4	5.1

Because marketing capacity remains tight and worldwide demand for wind turbines is very strong, a 2006 update added a market adjustment of $410/kW, an environmental/permitting adjustment of `$34/kW, and 5% construction contingency of $75/kW to the $981/kW base cost, for a total overnight cost of $1,500/kW in 2006 dollars for a 100-MW plant built during 2006 with a 2007 start up. Operating expenses in Table E-4 are escalated to 2007 dollars and major maintenance expense is increased to $6.00/kW in 2007 dollars.

Under the 2006 case assumptions, COEs are all about three quarters of a cent higher, in 2004 dollars, than the COEs in Table E-5. With no PTC, COEs, levelized in 2004 dollars, are: 7.7 cents/kWh IPP, 7.2 cents/kWh GenCo, 6.9 cents/kWh Portfolio, and 8.0 cents/kWh All-Equity.

Because market conditions continue to change, to analyze a project at a specific location, one must gather specific capital cost and the latest wind performance and operating expense inputs for that site.

Appendices

Four appendices are attached. Appendix A describes fixed charge rate calculations for the 2002 Reference Turbine technology, using two methods and contrasts it to 2000 technology. It also lists three examples of calculating variable expenses. Appendix B briefly discusses the increase to COE caused by decreasing the project life from 30 years to 20 and reports three ways to state the COE of a wind project. Appendix C summarizes COE and financial results for 2004 business conditions in a 100-MW plant under various ownership/financing assumptions, and Appendix D does the same for 2006 business conditions.

Financial Appendices

Several appendices are also attached for various financial ownership cases. Each includes summary pages, earnings, cash flows, and debt repayment, followed by a graph. Appendix E is a 30-year set of financials for the 2002 Reference Turbine, as a GenCo with no PTC.

All of the additional Appendices are for 20-year projects. Appendices F, G, and H include updated 2004 business conditions, as a GenCo with no PTC, with a PTC that is not monetized, and with a monetized PTC, respectively. Appendices I, J, and K include updated 2004 business conditions, as an IPP with no PTC, with a PTC that is not monetized, and with a monetized PTC, respectively.

Primer: The Wind Energy Program's Approach to Calculating Cost of Energy

1.0 Background

Cost of Energy (COE) is the indicator that is most often used to describe how well wind-generated electricity can compete in the marketplace. COE is a valuable indicator of the changing performance of wind technology. To say that the cost of wind power has declined nearly ten-fold since 1980 strongly indicates how rapidly the technology has advanced during that period. Further, COE is an essential element of analytical efforts to project plant and equipment technology and operating improvements and to forecast wind energy's utilization. Levelized COE is a widely used measure for the U.S. Department of Energy (DOE), its Wind Energy Program and for the National Renewable Energy Laboratory (NREL).

However, as this Primer describes, COE can be calculated and expressed in many ways. This document was prepared for two reasons. The first is to provide DOE/NREL program stakeholders with a clear description of how the program calculates COE for wind power—including both methodology and data assumptions. The second is to open a dialog with all industry players—developers, manufacturers, power purchasers, and investors—that could lead to improved program approaches to determining the competitiveness of wind.

Tracking the Development of Advanced Turbine Technology

The Wind Energy Program's Low Wind Speed Technology (LWST) and the Distributed Wind Technology (DWT) subkey activities both use COE as their primary figure of merit. Work with the LWST effort is the subject of this report. The advanced technology cost analyses supporting LWST efforts were updated to focus on estimating the COE from "Reference" technology, for a 2002 turbine, reflecting market conditions in October 2001. As will be detailed later in this report, that 2002 turbine had a constant dollar levelized COE, in 2002 dollars, of 4.8 cents/kilowatt-hour (kWh), excluding the Section 45 Production Tax Credit (PTC).

At the end of 2004, the program performed its annual update of the COE assessment. That assessment, known as the "Annual Turbine Technology Update (ATTU)," yielded a value of 4.4 cents/kWh, in 2002 dollars. The process for estimating the ATTU COE is described in *Low Wind Speed Technologies Annual Turbine Technology Update (ATTU) Process for Land Based, Utility Class Turbines*, by S. Schreck and A. Laxson, 2005, (NREL TP-500-37505). At the end of 2006, the ATTU COE was 3.9 cents/kWh, in 2002 dollars.

Discussion on reducing costs through specific technology improvements (e.g., composite material wind blades, taller towers on strong foundations, learning curve effects), as part of a technology pathways analysis, will be presented in *Technology Improvement Opportunities for Low Wind Speed Turbines and Implications for Cost of Energy Reduction*, by Cohen, Schweizer, Laxson, Butterfield, Schreck, Fingersh, Veers and Ashwill, to be published by NREL in 2008. While the ATTU COE result is valuable for tracking the progress of LWST research, because it uses cost and performance estimates for technology that has not been deployed in quantities of 100 megawatts (MW) or larger, it should not be interpreted as being indicative of commercial technology at that time and should be described as an advanced technology COE.

Different Ways of Expressing COE

When the Wind Energy Program calculates COE, it is referring to the cost of producing power, not the retail price of wind-generated electricity. Stated in utility terms, it is the producer's cost of delivering the wind-generated electricity to the utility busbar, or substation, and does not include the cost of transmitting the electricity over the grid or the marketing and distribution costs associated with retail sales.

COE can be expressed in several ways. While each of these ways produces a different numerical value for COE, they are all, in fact, comparable representations of the same project. For this reason, it is critical to state how COE was calculated.

Year 1 COE – The simplest way of expressing COE is to quote the nominal cost per kWh of power produced in the first year of a project. This would usually be the first year price or tariff to be paid by a wholesale purchaser in a multiyear power purchase agreement (PPA), often referred to as the "bid price." Over time, PPAs specify how the tariff will escalate, at a percentage rate or with an index or otherwise. If the annual escalation rate is constant, then the first year price and the escalation rate uniquely specify the cost of wind from the project. However, in many instances the escalation rate is not uniform, with the rate changing or possibly with some one-year price interruption, up or down, at some later period of time. In those cases, it is necessary to cite the first change points and the subsequent rates of change or possibly to list the power purchase price for each year, to understand the true cost of wind.

Current Versus Constant Dollars – COE analyses can be expressed in terms that either include or exclude general inflation. Analyses with inflation are referred to as current dollar analyses, also known as nominal dollar analyses. Analyses without inflation are termed constant dollar analyses. For the 2002 Reference Turbine and earlier work, U.S. inflation was estimated at 3%. Shortly afterwards and to the present day, inflation has been estimated at 2.5%.

Levelized COE – The process of levelizing a revenue stream turns a varying and possibly non-uniform stream of revenues into one single figure of merit, thus forming a uniform series. First, the analyst determines the net present value (NPV) of the project's revenue stream. The NPV discounting is performed using a nominal discount rate. The Wind Energy Program uses the weighted average cost of capital of a typical investor owned utility (IOU) that would buy power or would produce competitive power. Lately, the discount rate is estimated at 8.5%, assuming 2.5% inflation and an IOU with 50% debt at 6.5%, 5% preferred at 6.3%, and 45% common stock at 11%.

To figure the project's nominal NPV, one may either discount each year's revenue to present value (as rev / [1.085^n]), where n is 1 through 20 or 30, and sum the figures or apply an NPV formula to the raw revenue stream. Either method yields the same answer.

Second, from the nominal NPV, the annual constant-dollar levelized cost is calculated. The constant-dollar discount rate is 5.85%, calculated as [(1 + nominal rate)/(1 + inflation) -1] or [1.085/1.025 -1]. The formula for constant-dollar levelized cost is [nominal NPV * constant$ rate] / (1 – (1 + constant$ ate)^(-n)), where n is the number of years in the revenue stream. The levelized unit COE is the constant-dollar levelized cost divided by the annual energy production, to yield constant cents per kWh.

As another example, if inflation were 3%, and if the IOU financing was 50% debt at 7%, 5% preferred at 6.8%, and 45% common stock at 12%, then its cost of capital and the nominal discount rate would be 9.25%. The constant-dollar discount rate is 6.07%, as [1.0925/1.03 -1]. Note that this is the original LWST reference financing case – as detailed in Appendix A.

As stated, the program reports COEs in levelized constant dollars, which exclude inflation, for reasons to be discussed in Section 2.0. The program excludes use of the Section 45 Production Tax Credit because it is not a permanent part of the tax code and sometimes lapses.

Effect of Project Financial Structure on COE

Typically, wind projects are financed through a combination of both debt and equity. Debt is money that is borrowed where a sum certain is guaranteed to be repaid by a fixed maturity date and at a specified, limited return. Equity is money raised from investors who buy an ownership share in the project and a pro rata or some other contractually-specified share in income. Unless the PPA allows a pass-through of interest rate risk, lenders tend to require that debt employ a fixed interest rate (or that variable rates be hedged or swapped, which increases the cost to be about equivalent to that of a fixed interest rate).

Because it is less risky (i.e., gets paid first from project revenues and holds first claim in the event of default), debt is less expensive than equity. Equity investors shoulder the largest portion of the risk associated with project performance and, while they share in any favorable upside, their return is not guaranteed and may be lower than projected. In the worst case, if a project defaults on its debt and a work-out cannot be negotiated, the lender may seize the project and equity investors lose everything. As will be discussed in Section 2, the ratio of debt to equity used to finance a project has a significant effect on COE.

Wind projects can be developed by regulated utilities and non-regulated power producers. The cost-based system of revenue requirements approach used by regulated utilities is well-documented and has been used in rate-making processes for decades. The market-based discounted cash flow return on investment (DCF-ROI) approaches used by non-regulated power producers vary widely, with use of non-recourse or recourse debt and the relative fraction of debt to equity being key differences among them. Four market-based, non-utility approaches used by the wind community include: Project Finance , Balance-Sheet (GenCo) Finance, Portfolio Finance, and All-Equity Finance.

The program has used the GenCo Finance approach since 1997. Section 2 sets forth capital cost, performance and operating expense assumptions for a wind energy plant. It describes use of the GenCo approach to calculate a COE for the LWST program's Reference Turbine. Before 1998, the Wind Energy Program characterized wind projects using more highly leveraged independent power producer (IPP) project finance. Informally, it sometimes runs a second set of COEs for comparison using IPP assumptions. Section 2 also describes these informal IPP calculations.

Section 3 describes two other financing structures. To bring the analyses more into line with current industry practice, Section 4 describes changes to certain assumptions (e.g., 20-year project life versus older estimate of 30 years, increased capital cost of selected components). Section 4 sets forth the wind energy COEs under 2004 business conditions and under a 2006 update, calculated under each of the four ownership assumptions.

2.0 The Wind Program Approach to Calculating COE

COE has always been a key program metric for DOE and NREL, and in recent years, has become the program's most visible performance tracking and reporting metric under the LWST element of the program. The President's Management Agenda requires annual reporting of progress toward achieving the LWST goal of 3.6 cents/kWh (in 2002 dollars) in 2012, in Class 4 winds. This requirement has raised the visibility of the goal with industry and naturally invites comparison of the program's reporting of COE with that of industry and the press.

The estimation of COE, for purposes of tracking the development progress of advanced wind technology, as under the LWST activity, produces COE results that are quite different from how real-world COEs are calculated and expressed.

Key Assumptions

1) Constant-dollar COE, excluding inflation: The first difference comes from the fact that the program quotes COE in levelized *constant* dollars, which exclude inflation. This differs from the real world that thinks in terms of nominal, or current, dollars. There are a variety of reasons why the program removes inflationary effects from the advanced technology COE:

1. To more fully isolate the technology improvements that contribute to real overall COE trends from temporary short-term events, as well as more general economic effects like the assumed inflationary environment.
2. To facilitate comparison of results over a long time frame—the same technology, although installed in very different years, would have the same apparent COE.
3. To make the levelized value appear closer to and a better match to first year avoided cost, which is a principal comparative metric.
4. Economists in DOE and other parts of the federal government tend to perform the analyses in their economic models in constant dollars.

For a capital-intensive power plant project, constant-dollar analysis requires careful attention regarding depreciation, debt and taxes. Analysts calculate depreciation based on historic cost (not replacement cost). They calculate debt repayment in historic, nominal dollars (e.g., at a fixed interest rate and where principal does not escalate with inflation, but revenues and expenses do escalate, to some extent). Analysts figure income tax with a tax rate that applies to nominal, inflated earnings. Consequently, the program calculates wind energy project economics on an inflated basis over 20 or 30 years, including depreciation, debt and tax payments, and then deflates to obtain constant-dollar COE.

2) Levelized COE: The program's advanced technology COE value is also *levelized*, where a series of prices are converted to one uniform price that holds for the life of the project. This makes it different from projects that are characterized only by their year 1 price. The net result is that some amount of effort is required to compare the LWST advanced technology COEs to industry COEs. Figure 1 illustrates the differences in COE, when expressing it in different terms. As shown, the constant-dollar levelized COE is lowest. The constant-dollar COE is lower than the year 1 price because all years

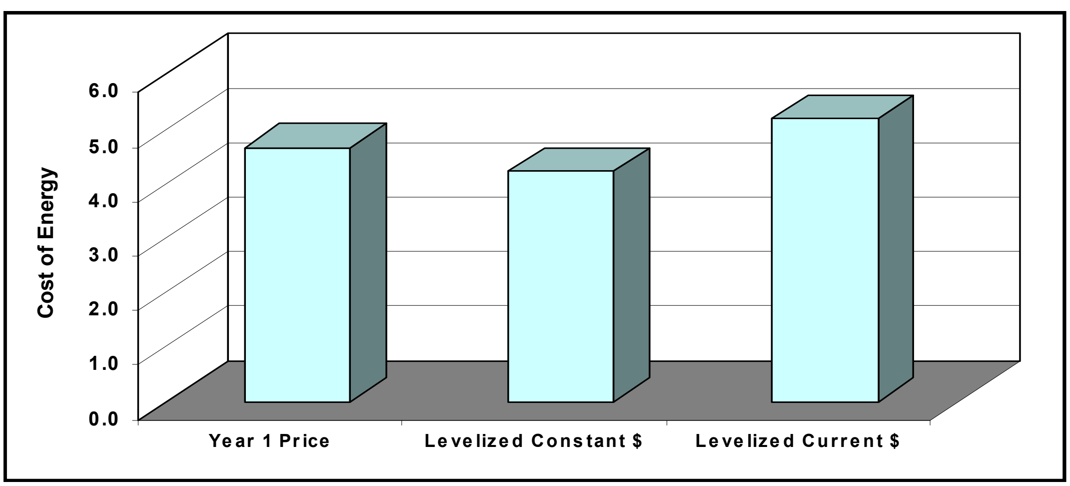


Figure 1. Comparison of Ways of Expressing COE for a Sample Project

are discounted back to year zero (the construction year) by a discount rate that is greater than inflation, then added together for the NPV, and finally, levelized into one price.

3) Excluding PTC: Because the Section 45 Production Tax Credit is not a permanent part of the Tax Code, the program does not include it. This differs from industry practice, where the PTC is employed and occasionally is monetized or considered as a stream of cash such that it can be used to repay debt.

Key Examples

The program's analysts utilize and provide wind cost and performance data for a variety of purposes, including various modeling efforts. For example, under the Government Performance and Results Act (GPRA) of 1993, enacted as P.L. 103-62, DOE's Office of Energy Efficiency and Renewable Energy (EERE) estimates benefits of its Congressional budget requests. EERE estimates benefits for its overall portfolio and each of its nine operating programs, including the Wind Energy Program. The program's inputs to the NEMS-GPRA 08 model are set forth in Projected Benefits of Federal Energy Efficiency and Renewable Energy Programs: FY 2008 Budget Request (NREL/TP-640-41347), prepared by NREL and dated March 2007. As summarized in Appendix E of this report, the Wind Energy Program's model inputs include capital costs, operating expenses, and capacity factors, estimated in 5-year increments from 2005 through 2030 and in 10-year increments through 2050, with all costs expressed in 2004 dollars.

Finally, the program needs to measure progress to research, develop, demonstrate, and deploy advanced wind energy technology. Opportunities for such progress are described as part of a five-step technology pathways analysis, in *Technology Improvement Opportunities for Low Wind Speed Turbines and Implications for Cost of Energy Reduction*, by Cohen, Schweizer, Laxson, Butterfield, Schreck, Fingersh, Veers and Ashwill, to be published by NREL in 2008. Other research and development (R&D) efforts are described in other reports. The metric employed by most all these activities is the constant-dollar, levelized COE that excludes PTC.

Reference Turbine Capital Costs

So far, this paper has discussed underlying financial methodologies and assumptions. The next element of the COE calculation is estimating project capital cost, plant performance, and project operating expenses and charges. Project cost includes costs to purchase and install turbine hardware, to prepare the site, and to purchase and install supporting balance of station (often called hard costs) and costs to finance and legally structure the project (often called soft costs). The answer to the question "how much does a wind turbine cost?" is quite different from the question "how much does a wind plant cost?" Because it includes not only the turbine but all other costs, only the wind plant cost is relevant to answering the question regarding the COE of wind energy.

In their jointly published book, *Renewable Energy Technology Characterizations* (EPRI TR-109496), dated December 1997, DOE and the Electric Power Research Institute (EPRI) collaborated to study plant costs. They started by forecasting plant cost and performance for wind energy and other renewable energy technologies from the present to year 2030. They specified, identified, and described component equipment and forecast component costs, looking at both 5-year and 10-year intervals.

In building on this work, NREL prepared a statement of work for the Next Generation LWST Project, and the turbine system cost is specified to include:

- rotor assembly
  - blades
  - aerodynamic control system
  - rotor hub

- miscellaneous costs, including labor for factory assembly of rotor components

- nacelle assembly
  - low-speed shaft, bearings and couplings
  - gearbox
  - generator
  - mechanical brake system
  - mainframe (chassis)
  - yaw system, including drives, dampers, brakes and bearings
  - nacelle cover
  - work platform
  - miscellaneous costs, including labor for factory assembly of the nacelle component
- tower (less on-site assembly costs included in "installation" below)
- control and electrical systems, including labor for factory assembly
- shipping costs, including permits and insurance
- warranty costs, including insurance
- mark-up, including royalties, profit and overhead not included above.

Immediately afterwards, in the Statement of Work, the balance-of-station cost is specified to include:

- wind resource assessment and feasibility studies
- surveying
- site preparation, including roads, grading and fences
- electrical collection system infrastructure
- substation
- foundations for the wind turbines
- operation and maintenance (O&M) facilities and equipment
- receiving, installation, checkout and startup
- wind power plant control and monitoring equipment
- initial spare parts inventory
- permits and licenses
- legal counsel
- project management and engineering
- construction insurance
- construction contingency.

For 2002, the program estimated that wind plant and equipment costs were as shown in Table 1. These 2002 turbine cost estimates have become part of what DOE and NREL refer to as the “Reference Turbine” technology characterization. It is part of the analytical baseline used for tracking advanced technology development.

Note that certain cost components from the Statement of Work were grouped and not listed separately in Table 1. For example, shipping and warranty costs were not listed with the turbine system. Wind resource assessment and feasibility studies, spare parts, legal counsel, construction insurance, and construction contingency are not listed under balance of station.

It is recognized that certain industry observers consider wind studies, construction insurance, permits, legal counsel, and so forth to be “soft costs” that are not part of the balance of station. However, they are classed as balance of station in this analysis.

As Table 1 shows, the total overnight capital cost for the 1.5-MW Reference Turbine that is part of a 100-MW wind plant is $981/kW, in 2002 dollars. Component costs include turbine capital cost at $614/kW, balance of station at $259/kW, and manufacturing uncertainty at $108/kW. Manufacturing uncertainty is the manufacturer's mark-up or profit margin. DOE'e earlier estimate for current technology wind turbines in a 100-MW wind plant was $950/kW, so the 2002 cost shows a slight increase.

The hardware cost components for the 2002 turbine system and balance of station are shown in graphic form in Figure 2.

Table 1. Hardware Costs for the Reference Turbine, a 1.5-MW Turbine Installed in a 100-MW Wind Plant (in 2002 dollars)

Component	**Component Cost ($1000)**		**Component Cost ($/kW)**
Rotor		248	165
Blades	149		
Hub	64		
Pitch mechanism & bearings	36		
Drive Train and Nacelle		563	375
Low-speed shaft	20		
Bearings	12		
Gearbox	151		
Mechanical brake, high-speed coupling, etc.	3		
Generator	98		
Variable-speed electronics	101		
Yaw drive and bearing	12		
Main frame	64		
Electrical connections	60		
Hydraulic system	7		
Nacelle Cover	36		
Control, safety system		10	7
Tower		101	67
TURBINE CAPITAL COST		**921**	**$614/kW**
Foundations		49	
Transportation		51	
Roads, civil works		79	
Assembly & installation		51	
Electrical interconnect		127	
Permits, engineering		33	
BALANCE-OF-STATION COST		**388**	**259**
Market Price Adjuster		**162**	**108**
INITIAL OVERNIGHT CAPITAL COST		**1,472**	**$981/kW**

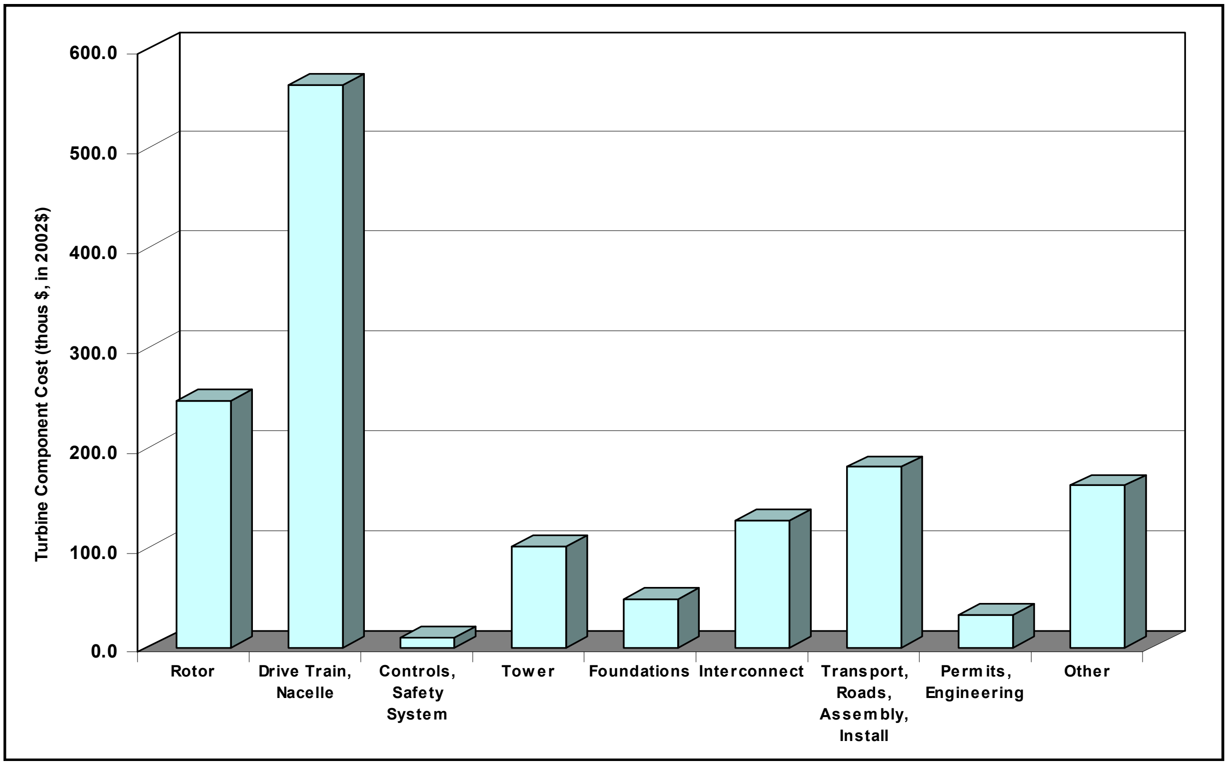


Figure 2. Cost Elements of the 1.5-MW Reference Turbine (thousand 2002 dollars)

Total capital cost to complete the wind energy plant consists of the plant and equipment costs in Figure 2 and Table 1, plus the soft costs associated with financing and legal structure of the project. These soft costs include fees for raising debt and equity, including tax advice, interest during construction, and reserves.

Total capital costs to complete the wind energy plant are listed below in Table 2. For ownership by a GenCo, soft costs are the lowest of all the ownership/financing options. As shown in Table 2, soft costs for GenCos include interest during construction. They also include an allocation of home office overhead equal to 1% of the total hardware costs to cover the wind plant's share of financing expense. For the Reference Turbine, these soft costs raise the total installed project cost to $1041/kW.

For other ownership scenarios, the soft costs are higher, reflecting the additional costs of raising project funds and establishing a new business entity. For example, for the informal IPP case in Table 2, soft costs also include interest during construction. However, instead of 1% home office overhead, the IPP pays debt and equity financing fees, including for tax advice, and puts up a six-month Debt Service Reserve Fund, consistent with a Better Business Bureau (BBB_-rated project. Table 2 shows the Reference Turbine under IPP ownership and finance costs $1,099/kW, which is over $50/kW greater than as a GenCo. When capital costs are higher, the difference between the soft costs for GenCo and the other ownership types can be up to $100/kW. If the GenCo does not pay a developer's success fee/construction contingency, the difference can be up to $150/kW.

Furthermore, if the wind energy plant endures special conditions, such as a remote and rocky location, then transportation and installation costs are increased. If the plant is located far from utility interconnect, then a transmission cost adder is needed. If there are special wind assessment or bird migration studies required, then balance-of-station costs are increased.

Note that there is no line item in Table 2 for a developer's fee. As the wind industry has matured, DOE assumed the developer took much of his or her profits as an owner, that is, as part of the equity return, and therefore, no fee is shown as a capital cost. Some developers may take some profits as an operator, over time, as part of O&M expense. However, DOE recognizes that, in other cases, for example if the developer is a builder, equipment vendor, or engineering firm, they may also take some profits during design and construction as a fee. Regarding developer fees and soft costs, there is always an inherent tension to try to lower total loaded cost, so equity investor returns can be increased and/or COE or the tariff charged to end consumers can be reduced. For certain difficult or small projects, a "developer's success fee" that partly doubles as a project contingency may also be charged. Despite these various scenarios, DOE chose to keep such fees and costs out of the initial capital cost for the Reference Turbine.

Table 2. Total Loaded Cost for the 1.5-MW Reference Turbine in a 100-MW Wind Plant (in 2002 dollars)

Component	**Cost ($1000)**	**Cost ($/kW)**	**Cost ($1000)**	**Cost ($/kW)**
	GenCo Balance Sheet		**Project (IPP) Finance (informal only)**	
Turbine Capital Cost	921	614	921	614
Balance-of-Station Cost	388	259	388	259
Manufacturing Uncertainty	162	108	162	108
Initial Overnight Capital Cost	**1,472**	**981**	**1,472**	**981**
Construction Loan Interest	74	50	75	50
GenCo Home Office Overhead (1%)	15	10	--	--
Debt Financing Fees (2% of debt)	--	--	23	15
Equity Financing Fees (3% of equity)	--	--	15	10
Debt Service Reserve (6 months)	--	--	64	43
Total Loaded Cost	**1,561**	**1,041**	**1,649**	**1,099**

Reference Turbine Performance and Operating Expenses

As stated, the 1.5-MW Reference Turbine is part of a 100-MW plant that was built during 2002 and started up in January 2003. The wind resource conditions are assumed to be a wind Class 4 site, at sea level with an annual average wind speed of 5.8 meters per second (m/s) at 10 meters (m) above ground, using a Rayleigh distribution, and a wind shear exponent of 0.14. The net annual capacity factor is 33.8% for 2002. Therefore, the 1.5-MW Turbine produces a net output of 4.44 million kWh/yr/turbine (as 1,500 kW * 24 hr/day * 365 day/yr * 0.338). This estimate is based on data provided by industry and the NREL-supported WindPACT studies. The 100-MW plant produces 296 million kWh/year.

The 2002 capacity factor of 33.8% shows a significant increase over year 2000 technology, where the capacity factor was 25.1%. This reflects the jump in scale from a nominal 750-kW turbine to a 1.5-MW turbine, with the latter also incorporating more advanced technology and design tools, allowing larger rotors to be utilized with relatively smaller increases in other system component weights.

In addition to capital costs, a wind energy plant incurs operating expenses over time. These are estimated as shown in Table 3. Note that expenses are specified in 2002 dollars but plant start-up is 2003, so O&M, land rent, and insurance will escalate once by inflation for the first year's operation (final column).

Table 3. Performance and Annual Operating Expenses for the 1.5-MW Reference Turbine Installed in a 100-MW Wind Plant (all 2002 dollars, except final column)

Component	Cost/turbine ($/yr)	Cost/kW ($/kW/yr)	Escala-tion (%)	$Cost/turb. in 2003
Performance	33.8% capacity factor			
Inflation	2.5%[1]			
Operations and Maintenance	30,000	20.00	Inflation	30,750
Site Owner Land Rent (or Royalty) – actual[2]	5,000	3.33	Inflation	5,125
Property Tax	15,607[3]	10.40	Zero[4]	15,607
Insurance	15,607[3]	10.40	Inflation	15,997
Major Maintenance & Overhauls	16,000[5]	10.70	Zero[5]	16,000

1) Inflation was estimated as 2.5% by late 2001. An estimate of 3.0% and slightly higher financing costs were used earlier. See Appendix A.
2) For the LWST project where fixed charge rate (FCR) calculations are employed, site owner land rent is specified higher, as 0.1845 cents/kWh, based on a royalty that is 3% of revenues and using a 25.1% capacity factor. This becomes 0.108 cents/kWh levelized in constant 2002 $, after applying a 60% after-tax factor. Then the cost/turbine is $8,200 and the cost/kW is $5.46, in 2002$, escalating by inflation.
3) Calculated as 1% of depreciable base (initial capital cost + construction loan interest).
4) Because escalation in assessment is offset by write-down in equipment value due to wear-and-tear.
5) This value is the levelized annual payment to a major maintenance reserve over 30 years. Under the program's historical assumption of a 30-year life, major maintenance is estimated to be 5% of depreciable base in year 10 and 15% of depreciable base in year 20, escalated for inflation and paid from an equipment reserve fund with annual deposits of one tenth of cost. Therefore, reserve fund deposits per turbine per year are $9,410 in years 1-10 and $36,150 in years 11-20. Overhauls are recovered through 10-year, straight-line depreciation. Escalation for major maintenance is zero because, while anticipated payments were escalated by inflation to determine the year 10 and year 20 overhaul charges, when the yearly deposit to the major maintenance reserve fund is expressed as a levelized payment, there is no additional escalation.

Reference Turbine Financing Structure

The program assumed plant ownership under the GenCo financial structure in calculating the Reference Turbine COE. The program stipulated that LWST subcontractors would perform their COE calculations using a methodology supplied by the program, and calibrated to GenCo ownership. This decision developed as described below.

In response to the energy crises of the 1970s, Congress enacted the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA began the process of loosening up the competitive landscape and opened the door for non-utility entities to generate and provide power to the grid. The Energy Policy Act of 1992 (EPACT) further increased competition in generation by allowing exempt wholesale generators to generate and sell electricity wholesale, without being regulated as utilities under the Public Utilities Holding Company Act (PUHCA) of 1935. Private power approaches to project ownership and financing evolved with this legislation and with national and global energy supply and demand and economic trends. Recently, the Energy Policy Act of 2005 repealed the PUHCA of 1935, replacing it with a books and records access law that allows the Federal Energy Regulatory Commission (FERC) to inspect utility holding company books. This change eventually may draw significant investment funds from new sources.

Project (IPP) Finance – The early private power producers, following passage of PURPA, built renewable energy and cogeneration plants that were termed qualified facilities (QFs) under Section 210, which required regulated utilities to buy their power at avoided cost. Over time, QF developers became the more general IPPs, which tended to be independent companies affiliated with large engineering or other companies, or the non-regulated affiliates of public utility holding companies. The IPP financial structure for owning power plants tended to be highly leveraged (having a large proportion of debt), with investment that was non-recourse to (not secured by) the developer/owner and that was secured only by the one project (hence the term, project finance).

To reassure investors, the project needed to sell power to a credit-worthy utility or other power purchaser under a long-term Power Purchase Agreement (PPA). IPPs further spread risk by seeking out a turnkey contractor to build the plant under a fixed price contract and an experienced plant operator to perform O&M. To reduce risk in fuel supply, especially overseas, the IPP sometimes sought out a power purchaser that would also supply fuel, which reduced risk of a cut-off or profits squeeze, but this is a problem wind plants avoid. Early U.S. projects frequently relied on tax incentives like rapid depreciation and investment and production tax credits, to provide attractive returns to investors. Consequently, developers sought outside equity investors, in the highest tax brackets, who might invest as limited partners and who could fully utilize the tax benefits. IPP developers utilized so-called "pass-through entities," such as partnerships (and later limited liability companies) where tax benefit/liabilities and cash are allocated to the partners. This contrasts with incorporated companies that pay income tax at the corporate level and do not pass along tax credits and where dividends to common stockholders are taxed twice.

Because wind projects were largely being constructed by IPPs using project finance, the program used to characterize wind projects in those financial terms. As the wind energy industry has matured and as the power market has shifted toward competitive power procurement, the highly leveraged IPP financial structure has shifted. Lenders require a larger equity share, from the developer or outside equity investors. High fees to brokers and tax lawyers are reduced—from 5% to 10% of project debt and equity to approximately 2% to 3% for recent years. However, the debt service reserve remains an example of negative arbitrage, where one borrows at about 7.0% and earns a reinvestment rate of about 3.0% or less. Occasionally, to avoid the negative arbitrage, developers pay for credit enhancement (e.g., a bank letter of credit, where they pay a fee such as 0.75% on the outstanding loan balance). But despite improvements, critics still see Project Finance as inefficient.

Balance-Sheet (GenCo) Finance – Project (IPP) Finance developed out of necessity, as the first QF developers lacked the corporate balance sheet and corporate assets to secure financing. Traditional investor-owned utilities built power plants that were financed with general corporate debt and equity, issued by a large corporation with a good reputation and an on-going business. Traditional IOUs owned power plants outright.

During the late 1990s, as wind became a more competitive option for utility-scale power, and as developer/sponsors became larger and more established, industry observers expected high-cost Project (IPP) Finance to be used less. They expected the larger developers within the wind development community to sell bonds and stock like the traditional utility or any other large corporation and use that cash and internally generated funds to build plants. Many references exist, but arguments are clearly articulated and developed by Anthony A. Churchill, senior adviser to Washington International Energy Group, in "Beyond Project Finance," EuroForum, Second Annual Global Energy Finance Conference, London, February 13-14, 1995.

This balance sheet financing approach became known as GenCo (short for generating company). Internally generated funds reflect a corporation's underlying debt to equity ratio, and sustainable debt for an established, capital-intensive energy company is lower than for a high-growth, new start-up. Because of reduced risk, the use of recourse debt and equity results in a lower overall required return on investment. Because debt and equity investors are secured by the GenCo's balance sheet, they do not require a PPA and the plant is assumed to sell power on a merchant basis. The program has been using this GenCo approach to estimate COE since 1997.

Future Outlook – At present, industry observers are split on the outlook for these two financing/ownership approaches. Sometimes, the electric power plant construction manifests a "boom and bust" cycle, where merchant plants especially would be hurt during periods of over-capacity. Private power projects are getting bigger, e.g., growing to 200 MW from 5 MW to 50 MW. The private developer does not have a guaranteed service area, unlike the traditional regulated utility. Further, developers want to protect corporate assets and reduce outside claims.

Consequently, developers are cautious. Lately, their preferred mode of action seems to be to finance private power plant projects with corporate equity (provided alone or with partners) and to use project-specific non-recourse debt that holds no claim to the parent company. Often they employ PPAs, which are almost always a requirement of a lender who is providing non-recourse debt. Recently, instead of a PPA, financial hedging has been employed against variability of wind resource to guarantee a level of output with, for example, 95% or 99% probability (termed P95 or P99 output cases), where the hedge might run five years in duration. Sometimes developers seek permanent "take out" financing, by selling completed plants to new debt and outside equity investors who want less risk than building would involve, on the scale of either one plant or a pool of plants.

As a point of clarification, the reader should note that the program assumes that under Project (IPP) Finance and All-Equity Finance (to be discussed in Section 3.0), investors are secured only by the project itself and have no recourse to the developer or other assets. By Portfolio Finance (also discussed in Section 3.0), they are secured by a pool of about six to ten projects. Under GenCo Balance-Sheet Finance, by contrast, a large established company is assumed to build, finance, and own the wind energy plant using internally generated funds, financed at the corporate cost of debt and equity capital. Investors in corporate stock and bonds have full recourse to all company assets. Should a large energy company build, finance and own a wind plant as an LLC (Limited Liability Company), then that company may use balance sheet finance in the early planning stages to move quickly, but it is employing limited or non-recourse Project (IPP) Finance, as its permanent take-out financing method.

Reference Turbine Financing/Ownership

Table 4 summarizes the assumptions used for the 2002 Reference Turbine COE calculation. GenCo Balance-Sheet Financing and ownership is employed. The Project (IPP) Finance data is informal and presented for informational purposes only.

Accordingly, the COE of the Reference Turbine, using the GenCo assumptions in Table 4, is 4.8 cents/kWh (levelized in constant 2002 dollars). In comparison, the Project (IPP) Finance COE is 5.3 cents/kWh (levelized in constant 2002 dollars). See Appendix A for additional discussion, including calculation of COE by a fixed charge rate.

Table 4. Financing Parameters Assumed for Reference Turbine COE Estimate

	GenCo Balance Sheet	**Project (IPP) Finance (informal)**
Lifetime	30 years	30 years
Inflation	2.5%	2.5%
Start Year	2003	2003
Construction Period	1.0 years	1.0 years
Debt/Equity	35/65	70/30
Debt Rate	6.5%	7.0%
Debt Period	28 years	15 years
Principal Repayment Schedule	Level mortgage-style [1]	Level mortgage-style [1]
After-tax Leveraged Equity Return	13% goal, and 13.08% actual	17% minimum goal, but 21.33% actual
Tax Rate	35.0% federal and 7.7% deductible state, so 40% combined	35.0% federal and 7.7% deductible state, so 40% combined
Debt Coverage	Not applicable, as loan is secured by owner's corporate assets. (Executive management wants 1.3 times minimum and project delivers 4 times minimum and 5.3 times average, as the actual coverage).	1.5 times worst year and 1.8 times average. (These guidelines are met, with average debt coverage as the tight constraint).
Revenue Escalation Rate	2%/yr, assuming 2.5% inflation	2%/yr, assuming 2.5% inflation
Section 45 Production Tax Credit	Available, but not included in DOE COE analysis	Available, but not included in DOE COE analysis
Energy Production	100%	100%
Depreciation	5-year MACRS[2] using half-year convention	5-year MACRS[2] using half-year convention
IOU Cost of Capital Discount Rate, by which to figure COE	8.5 nominal [3] 5.85 constant	8.5 nominal [3] 5.85 constant
Levelized Cost of Energy (constant $2002)	**4.8 cents/kWh**	**5.3 cents/kWh**

1) Level mortgage-style debt repayment is similar to that of a homeowner with a fixed-rate mortgage, with one level payment that is composed more of interest to start and more of principal at the end. Other debt repayment options are level principal payment and customized schedules that attempt to match some particular revenue or other schedule (e.g., seasonal patterns in the wind resource).
2) The wind energy plant is alternative energy property that takes a five-year recovery period, with all components assumed to be "closely related" to the main structure and eligible for the same tax treatment.
3) Discount rate is calculated as 50% debt at 6.5%, 5% preferred at 6.3%, and 45% common at 11%.

Table 4 shows that the program assumes start-up in 2003 for the 1.5-MW Reference Turbine, with a 30-year life, a 40% combined tax rate and 5-year modified accelerated cost recovery system (MACRS) depreciation, using the half-year convention. Therefore, annual fractions are: 20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%. Earlier, more aggressive depreciation was employed, using the mid-quarter convention, starting in quarter one, with fractions: 35%, 26%, 15.6%, 11.01%, 11.01%, and 1.38%. Because of the assumed January start date, it remains appropriate to use mid-quarter-quarter one depreciation. However, much of industry uses the half-year convention, where the plant can start up at any point during the year, and the program switched to match industry.

GenCo Balance-Sheet Finance Details – In their joint 1997 book, *Renewable Energy Technology Characterizations*, referenced earlier, DOE and EPRI used GenCo ownership and financing assumptions to standardize results. Many assumptions still held in 2001 for the LWST Reference Plant.

For the Reference Turbine, and as summarized in Table 4, GenCo corporate finance assumes a project at the BBB-rated level of standards, which is recourse and on-balance sheet to a BBB-rated company. BBB is the lowest rating that remains investment-grade, as determined by the bond rating agencies of Standard and Poors, Moody's, and Fitch. With an investment-grade rating, bonds are judged sufficiently "safe," that they may be purchased by a wider audience, including those institutional investors acting with prudence as fiduciaries, such as pension funds, certain mutual funds, banks and trust companies, college endowments, and so forth.

This energy project takes no PTC. The project is financed at the parent company's debt level, estimated at 35%, which is about average for large, well-established energy and natural resource companies (utilities, oil and gas, chemicals, metals).

To be conservative, given a 30-year project life, the GenCo debt term is set as 28 years and is repaid as a level mortgage. Otherwise, the debt term may be considered infinite, because the company maintains the same debt to equity ratio over many years. The project debt coverage ratio is moot, because lenders look to all the company's assets. (However, at only 35% debt with no tax credits, debt coverage tends to run 3 times or better, which is needed for the BBB rating, given no PPA. With the PTC, if project debt coverage looks too thin, executive management may demand a minimum such as 1.3 times. Debt coverage is calculated as annual operating income vs. the annual debt payment, composed of both interest and principal.) For a BBB-rated company and project, assuming inflation at 3%, the interest rate is estimated at a spread of 100 basis points or 1% over 30-year Treasuries, estimated at 6%, so GenCo 28-year, BBB-rated debt is 7%. In 2001, inflation shifted to 2.5% and 30-year Treasury rates declined to 5.5%. Therefore, GenCo 28-year, BBB-rated debt is 6.5%. (One basis point is 0.01 of 1%.)

Because their investment is diversified and secured by a pool of projects and BBB-rated corporate assets, the project is less risky and equity investors require only about a 13% after-tax return on investment. The merchant power price is estimated or, if a PPA is signed for the Project (IPP) Finance or other cases, the power purchase tariff is assumed to be negotiated as one starting value that escalates annually at one half percent less than inflation (i.e., at 2%, given 2.5% inflation) because, historically, in the United States, power prices increased slower than inflation.. For GenCo, the 13% equity return is the "tight constraint" that prevents COE from being reduced further.

Project (IPP) Finance Details – By contrast, as shown in Table 4, Project (IPP) Finance assumes a highly leveraged project at 70% debt for 15 years, given a 30-year project life, with no PTC; with PTCs, it is assumed that leverage will drop to 60% debt. The program assumed that project financial standards meet those of a BBB rating, regardless of whether the project is actually reviewed by a rating agency. Therefore, the project must sell power to a credit-worthy power purchaser under a PPA that runs 30 years or at least about 5 years longer than debt life. Because historical power prices in the U.S. have increased slower than inflation, it is a bargaining advantage if the IPP can offer a slow escalation rate. If the IPP finalizes terms and signs a contract with a power purchaser, then debt and equity financing will fall into place faster, followed by other pieces of the development effort. For the power purchaser, a guarantee, through the PPA contract that wholesale prices will not escalate faster than inflation is attractive and leaves the purchaser more likely to sign a PPA with this IPP project. Consequently, for the IPP, the power purchase tariff is assumed to be negotiated as one starting value that escalates annually at one half percent less than inflation (i.e., at 2%, given 2.5% inflation).

Because of the PPA, debt coverage is fairly low at 1.4 to 1.5 times for the worst year and about 1.8 times average. For a project at a BBB rating level, at 2.5% inflation, the interest rate is estimated at 7%. The interest rate is figured as a spread of 150 basis points over 30-year Treasuries at 5.5%, where the yield curve is fairly flat (so 15-year rates are close to those for 30-years). Note that if the IPP project could not receive an investment grade rating of at least BBB, the price for the debt securities, could "fall off a cliff," or in more conventional terminology, the interest rate would increase to a rate at 300 to 400 basis points over 30-year or comparable Treasuries. Note that when the program developed its assumptions in 1997 and 2001, the debt for many wind energy projects took the form of commercial bank loans that generally are not rated. Therefore, the program talked with investment banks, rating agencies, and others to learn what debt coverage and other standards ought to be met by a BBB-rated project. If a project is not rated, an entity can request a credit assessment, a shadow rating or other limited opinion, or a lender can request an agency-initiated rating. The developer has strong incentives to structure the project to reduce lender risk.

Because the risk to develop a project from early stages is high, the developer and any early stage equity investors, for whom the project is non-recourse and highly leveraged, require at least a 17% after-tax return on investment. In similar fashion to the earlier case, the power purchase tariff escalates annually from one starting value at one half percent less than inflation or 2% per year (2.5 – 0.5). For the IPP, average debt coverage of 1.8 times is the "tight constraint" that prevents COE from being reduced further and equity return works out to be higher than targeted, at 21.3%.

To fully utilize the project's return, including rapid depreciation and the Section 45 PTC, because some developers are not sufficiently large and consistently profitable in their U.S. operations, they need to seek outside equity investors as partners. The need to find partners or other outside equity investors with a so-called "large tax appetite" is a peculiar feature of wind project development.

If outside equity is needed, the financing may be structured as a limited partnership or other pass-through entity, where the developer serves as or sells out to a general partner (GP). The GP controls the project and assumes legal liability, even though they only put up a small portion of the equity investment. Most of the equity will be provided by the outside equity investors, who choose to be limited partners (LPs) or serve as some similar sort of passive investor, in return for which, they are shielded from legal liability and they receive much of the project's return, as tax benefits and cash, during some set initial period.

After the first seven to ten years, during which LPs have received payback plus an attractive return, the returns will "flip" or change, so that LPs receive a smaller share of project return, and the GP receives a larger share. For example, initial shares of tax benefits and cash may be 99% LP to 1% GP, flipping after 10 years to 50%/50%, and flipping again after an additional three years to 20%/80%. Sometimes investors will contractually agree that, in addition to the GP share based on capital investment, the GP receives a so-called "profits interest" or preferred return of a certain percentage (e.g., 20%) of profits. For the future, that the GP receives a larger share later is an incentive for the GP to keep the project up and operating into the long-term and not "run it into the ground." It is noted that some pass-through entities are complex, with parties agreeing by contract to various conditions, regarding legal, tax, and financial matters.

For the Reference Turbine, as shown in Appendix A, by late 2001, interest rates were falling, so the financing assumptions described in Table 4 were employed. Earlier, during summer and fall of 2001, inflation was estimated at 3%, 30-year Treasuries were estimated at 6% and IOU and GenCo debt employed a spread of 1%, so their debt rates were 7%. For IOUs, debt was 50%, preferred was 5% at 6.8%, and 45% common was 12%, for a cost of capital of 9.25% nominal and 6.07% constant. GenCo equity return was still 13%. These financing assumptions were included in the FCR calculations of the LWST Project, also as shown in Appendix A.

3.0 Alternative Approaches to Estimating COE

The previous section described how the program used the GenCo approach to estimate the COE of the 2002 Reference Turbine. It also described the Project (IPP) Finance approach. This section describes two other financing approaches currently being used by the wind industry.

Portfolio Finance – In recent years, another form of wind energy plant financing has emerged – the portfolio approach. Two forces are at work. First, contrary to the expectations of academic and industry observers, even very large energy companies did not want to jeopardize their corporate balance sheets for the long-term to permanently finance wind, gas-fed, and various other electric power plants. However, as the industry consolidated and developer/sponsors became larger, and as larger quantities of turbines were employed in more projects, it became attractive to pool multiple geographically dispersed projects together as a way of mitigating potential risks associated with financing a single project. In fact, Standard & Poor's Ratings Services (S&P), in 2003, gave an investment grade rating to a portfolio of seven wind plants (FPL American Wind LLC) at 697 MW that issued $380 million in senior secured bonds partly because "The portfolio is diversified with the use of five wind turbine technologies, four regionally independent wind regimes, and 12 offtakers." (Reuters, 12/05/03 – quoted at www.forbes.com/home_europe/newswire/2003/12/05/rtr1170984.html). Clearly, the idea of a diversified portfolio allowed the project to be financed in the more traditional marketplace. S&P also cited the conservative 52% leveraging of the project (meaning it had a relatively higher equity fraction) as an important consideration. Portfolio Finance has been used primarily as a way to structure long-term financing for projects, after the initial start-up period has passed.

Two other examples of Portfolio Finance transactions include that of FPL Energy National Wind LLC and Three Winds. On February 16, 2005, FPL Energy Nation Wind LLC raised $365 million as bonds (rated BBB-), at 5.608% for 19 years to cover nine geographically diverse wind energy plants, sized at 534 MW total. Revenues are obtained under strong PPAs with eight off-takers that cover almost all power from the plants. Section 45 PTC payments represent about 20% of revenues and are "monetized" or unconditionally guaranteed by FPL Group Capital notwithstanding changes in tax law or its ability to use credits, such that cash exists to repay debt. A smaller example of Portfolio Financing was Three Winds, dated September 2004, and sponsored 50/50 by Shell Renewables and Goldman Sachs, to raise $123.5 million for 15 years to cover three wind plants at 152.5 MW. This portfolio raised debt in the U.S. bank market. The syndication was successful, with many banks participating, but some considered the interest rate high and the debt was not rated.

All-Equity Finance – Recently, some wind energy projects have been structured as all-equity deals. Projects structured in this manner seek to meet the needs of passive equity institutional investors, who had not recently invested in wind energy and for whom the tax benefits of a project are critically important. They are attracted to wind's five-year depreciation and 10-year Section 45 PTC (and to 50% bonus depreciation, which was available as a short-term stimulus from September 2001 through December 2004, but is now expired). Paying taxes in the highest bracket, equity institutional investors do not include pension funds which are tax-exempt, but do include corporate investors, insurance companies investing to cover premium, certain banks, and families and high net worth individuals. They also invest in aircraft leases and affordable housing.

These tax-driven passive equity investors are concerned that debt holders are paid first if a project suffers financial trouble. Because debt carries a risk of default, investors also worry that the lender will seize assets. If a wind energy project defaults, equity investors not only lose their investment and prospects of future gain, but they face recapture of tax benefits related to partnership capital accounts. Because capital-intensive wind energy property employs rapid five-year depreciation, the capital account tends to go negative in the early years and, if the project defaults in the early years a partner must pay the negative capital account balance.

The project avoids any chance of default if it assumes no debt. With no debt, risk is reduced, the range of possible outcomes is narrowed, and the equity return can be lower, with a range of about 8% to 13%. The institutional investors are passive in that they do not want voting control of the project, but they protect themselves by working with experienced developers and by structuring the financing so the developer invests its own money into the project—say, 30% to 40%. All equity project structures often include a "flip" feature, where the allocation of project returns (including cash and tax benefits/liabilities) between different classes of investors, will flip or change, as set forth by contract, after a set period of years. Recent all-equity deals include those by Babcock & Brown and J.P. Morgan (formerly Bank One).

4.0 Assumptions for Financing Structures, Reflecting 2004 Business Conditions, Plus One Quick 2006 Case

As discussed, the Reference LWST COE estimate reflects wind turbine technology and market conditions as of October 2001. The COE was calculated as a constant-dollar levelized value, which excluded the PTC. Section 2 set forth assumptions employed in the estimate. To isolate and track technology improvements over time with COE, it is essential to establish a technology and financial baseline, and keep the financial parameters and assumptions fixed. However, to keep abreast of market developments, the program often updates various assumptions to match economic conditions and the latest practices of the industry. This section presents an update as of 2005. Certain key cost, operating, and financial assumptions have been revised since the LWST Reference Turbine analysis. The reader should note that subsequent developments between 2005 and 2007 have resulted in a continuing trend towards higher market prices for wind turbines and resulting cost of energy, compared to both 2002 and 2005 figures. The 2005 updates included:

1. Hardware costs, including certain balance-of-station costs, are increased by more than 25%.
2. Project life is set as 20 years versus 30 years. The project starts up in January 2005, following one years's construction during 2004.
3. GenCo debt term, at two years less than project life, is 18 years versus 28 years. IPP debt term remains 15 years, but it must be at least 5 years less than project life.
4. Interest rates and certain equity returns remain about the same and continue to follow long-term market trends. GenCo debt rates are 6.5%, figured as 10-year Treasuries at 5.5% plus a 1% spread. IPP debt is 7%, figured as 5.5% 10-year Treasuries plus a 1.5% spread. An analyst modeling a real-world case might reduce interest rates if market conditions warrant. However, the program does not want to produce a low COE one year that rises the next year, when technology does not change, with the increase only because interest rates rose. The program is conservative (slightly high) in setting interest rates.
5. General inflation holds at 2.5%. Revenue escalation is 0.5% less than inflation and holds at 2%.
6. Formal COEs continue to be run without the Section 45 PTC. However, in special cases, the PTC is added. In other special cases, where a credit-worthy, willing entity is able and will not back out from a strict guarantee of cash payments, a "monetized" PTC may be used to repay debt. These latter two sets of cases with the PTC are informational only.

These changes are described below. They apply to a 100-MW wind energy plant built during 2004 that starts up in 2005.

Capital Cost, Performance, and Operating Assumptions

Hardware Costs

After a survey of 2005 market costs for wind projects and discussions with many industry members, the program has added a "market adjustment" cost to reflect a number of factors, which are not believed to be fundamentally technology-related to the turbine cost estimate. For a plant constructed during 2004 that begins operation in 2005, this market adjustment is $200/kW or $20 million for a 100-MW plant. The contributors to this increase in market price are believed to be many, including increases in the cost of steel and manufacturing processes, in general, and unusual cost adders due to very tight current market conditions that are characterized by a high demand worldwide and temporary exchange rate imbalances. This change is shown as part of the turbine capital cost in Table 5.

In addition, under balance-of-station costs, an environmental/licensing adjustment is added to reflect higher costs for permitting, environmental studies, and licensing (including bird studies). This cost is estimated at $18.86/kW or $1.886 million for a 100-MW wind energy plant. Construction contingency, which is classified with balance of system, is added explicitly. Construction contingency covers miscellaneous other development costs, as well as unforeseen and emergency building costs. Construction contingency might also be termed the developer's fee, so its addition marks a change from past practice with the 2002 Reference Turbine. Construction contingency is estimated at 5% of hardware costs, not including the contingency. It is 5% of turbine capital cost, balance of station cost, and manufacturing uncertainty or $60/kW, which is $6 million for the 100-MW plant. As Table 5 shows, initial overnight capital cost is therefore $1,260/kW or $126 million for the entire plant.

Table 5. Updated Hardware Costs for a 100-MW Wind Plant under 2004 Business Conditions, plus Quick 2006 Assumptions (in 2004 dollars except final column) [

Component	Cost ($1,000)	Component Cost ($/kW)	2006 Component Cost ($/kW in 2006$)
Rotor (blades, hub, pitch mechanism & bearings)	16,502	165	165
Drivetrain and nacelle (low-speed shaft; bearings; gearbox; mechanical brake, high-speed coupling, etc.; generator; variable-speed electronics; yaw drive and bearing; main frame; electrical connections; hydraulic system; nacelle cover)	37,518	375	375
Control, safety system	667	7	7
Tower	6,733	67	67
Market adjustment	20,000	200	410
TURBINE CAPITAL COST	**81,420**	**$814/kW**	**$1,024/kW**
Foundations	3,234	32	32
Transportation	3,400	34	34
Roads, civil works	5,262	53	53
Assembly & installation	3,381	34	34
Electrical interconnect	8,437	84	84
Permits, engineering	2,180	22	22
Permit/environmental adjustment	1,886	19	34
BALANCE OF STATION COST	**27,780**	278	293
Market Priced Adjuster	**10,800**	**108**	**108**
Construction Contingency	**6,000**	**60**	**75**

Component	Cost ($1,000)	Component Cost ($/kW)	2006 Component Cost ($/kW in 2006$)
INITIAL OVERNIGHT CAPITAL COST	**$126,000**	**$1,260/kW**	**$1,500/kW**

At this time, manufacturing capacity for wind turbines remains tight and worldwide demand is booming. Consequently, for informational purposes only, a final column was added to Table 5, showing unit capital cost per kW for a hypothetical 100-MW plant built during 2006 that starts up in 2007. The market adjustment is $410/kW, the environmental/licensing adjustment is $33.86/kW, and the 5% contingency becomes $75/kW. Overnight capital cost is $1,500/kW, in 2006 dollars. The reader will note that one might inflate all the cost components and employ smaller adjustments, to achieve the same total of $1,500/kW, which is $150 million for a 100-MW plant.

In contrast to refined 2004 figures prepared from the 2005 industry survey, the 2006 update is something of a quick "ballpark" estimate. It was prepared after literature review and limited discussion. However, the quick 2006 case permits one to answer the question of what COEs would be if capital costs were higher.

In addition, at some point in the future, it might be useful to examine whether there are variations in some of these costs by ownership/financing type. For example, a large company might negotiate a discount for buying multiple turbines, as a large order. In a related vein, by learning curve effect, would construction contingency be reduced for large, established generating companies that build and operate many plants? Or do such companies buy just-completed or partly-started plants from small independents, in which case a full contingency is needed. For the present, the program assumed there was no difference in overnight capital cost among the four ownership/financing categories, including GenCo, IPP, Portfolio and All-Equity Finance.

Soft Costs

As hard costs increase, certain soft costs increase proportionately. As described earlier, soft costs include legal, accounting and brokerage fees associated with raising debt and equity, interest paid during construction, and reserves that are set up. Soft costs vary slightly between the ownership/financing scenarios, largely due to different debt fractions. For a specific plant, the developer will work closely with his or her builder, lender, equity investors, legal and tax counsel, and others to determine specific costs, fees, and reserves. However, soft costs may be estimated as:

- Construction Loan Interest or Other Financing – 10% rate applied to all hard costs, calculated as a level draw over a 12-month construction period. (To show the level draw, which assumes plant and equipment costs are paid evenly over the 12-month construction period, multiply by 50%.) It is noted that some developers pay less in the beginning and more in later months, so their construction financing is lower but level draw represents a conservative (slightly high) assumption.
- Debt Financing Fees – 2% of debt, amortized over loan life.
- Equity Financing Fees – 3% of equity, with the tax advice portion expensed in year one, part amortized over 5 years, and part excluded. (The Tax Code states that equity broker fees cannot be expensed by a project. Our rough estimate for equity financing fee is 3% of equity. Of this, 40% is tax advice expensed in year 1, 40% organizational fee amortized over 5 years, and 20% equity broker where the fee is excluded as a tax write-off. Obviously these percentages will vary by project. It is not critical to results.)
- Debt Service Reserve Fund – 6 months' debt payment for a project at a BBB rating level, which earns a modest rate of interest for short-term available funds, estimated at inflation plus 0.5%, which is 3%.

For GenCos, instead of financing fees, a home office overhead, estimated to be 1% of total cost, is applied and there is no debt service reserve. For all-equity, there is no debt service reserve.

Soft costs for GenCo and IPP are shown below as part of the total loaded costs in Table 6. Soft Costs for Portfolio Finance and All-Equity ownership/financing structures are similar and can be easily figured.

Table 6. Updated Total Loaded Costs for a 100-MW Wind Plant Under 2004 Business Conditions (in 2004 dollars, except last row)

Component	Cost ($1000)	Cost ($1,000)
	GenCo Balance Sheet (35% debt to 65% equity)	**Project (IPP) Finance (70% debt to 30% equity with no PTC)**
Turbine Capital Cost	81,420	81,420
Balance-of-Station Cost	27,780	27,780
Manufacturing Uncertainty	10,800	10,800
Constr. Contingency	6,000	6,000
Initial Overnight Capital Cost	**126,000**	**126,000**
Construction Loan Interest	6,000	6,000
GenCo Home Office Overhead (1%)	1,200	--
Debt Financing Fees (2% of debt)	--	1,970
Equity Financing Fees (3% of equity)	--	1,270
Debt Service Reserve (6 months)	--	5,410
Total Loaded Cost	**133,200**	**140,650**
Total Loaded Cost for 2006 plant under quick 2006 assumptions (in 2006 dollars)	**159,000**	**167,810**

As shown, total loaded costs are $133.2 million for the GenCo and $140.65 million for the IPP. Because of the debt service reserve and financing fees, loaded cost for the IPP is higher. In analyzing special cases, one may argue that a large GenCo realizes certain economies of scale in planning and building the wind plant, so the GenCo hardware costs and balance-of-station costs may be lower. However, as discussed above, it was assumed that a large GenCo bought a 100-MW wind plant that was started by a smaller developer. The GenCo appreciates the developer's hard-charging efforts to start the project and get the plant under construction, which balances the fact the small developer did not realize any cost savings from scale. In general, GenCos should have economies of scale so their plant and construction costs ought to be less. However, that is not true if the plant is started by a small developer from whom the GenCo buys the plant. Large companies *do* buy out small developers, who are energetic enough to start the project. Therefore, in this updated version, we assume that large companies pay construction contingency and developer fees.

In addition, for the quick 2006 case, at $1,500/kW, total loaded cost is listed in the last row of Table 6. It is $159 million as a GenCo and $167.81 million as an IPP.

Performance and Operating Expenses

From figures in Table 3 for the 2002 Reference Turbine, performance and operating expense for a plant under 2004 business conditions did not change much. Performance remains the same, at a 33.8% capacity factor. Inflation is 2.5%. Updated operating expenses are listed in Table 7.

Note that because the plant is assumed to start in January 2005, year one operating expenses are expressed in 2005 dollars. But with a one-year construction period, plant construction and equipment costs are expressed in 2004 dollars.

Table 7. Performance and Updated Annual Operating Expenses for a 100-MW Wind Plant Under 2004 Business Conditions Plus Quick 2006 Assumptions (in 2005 dollars, except first column and last row)

Component	Cost ($1,000 in 2004$)	Escalation (%)	Cost ($1,000 in 2005$)	Cost/kW ($/kW/yr, in 2005$)
Performance	33.8% capacity factor			
Inflation	2.5%			
Operations and Maintenance	2,017	Inflation	2,067	20.67
Site Owner Land Rent (or Royalty)	325	Inflation	333	3.33
Property Tax	1,332	Zero	1,332	13.32
Insurance	1,332	Inflation	1,365	13.65
Major Maintenance & Overhauls	488	Inflation	500	5.00
For the 100-MW, 2006 plant, all costs hold the same as shown in the two final columns, except they are expressed in 2007$, and major maintenance is increased to $600 thousand ($6/kW), also in 2007$.				

As shown in the table, under 2004 business conditions, O&M is estimated as $31,000 per 1.5-MW turbine or $20.67/kW. Land rent is $5,000 per 1.5-MW turbine or $3.33/kW. Property tax and insurance are calculated at 1% of depreciable base, and because underlying plant cost increased, they both increased. For special cases, they can be set higher or lower to reflect actual property tax rules or if an insurance agent provides a quote.

Regarding major maintenance, because project life is reduced to 20 years and previous major maintenance was estimated to take place in year 10 and year 20 for a 30-year life, changes were needed. It did not appear logical to stick to the same schedule—either performing one overhaul in year 10 and then running the plant into the ground or performing a second overhaul in year 20, for which the owner sees almost no benefit. Therefore, the program assumes an annual expense of $5/kW or $7,500 per 1.5-MW turbine, which is $500,000 per year for major maintenance. This figure represents a major maintenance cost level between that required for activities only in year 10 and activities required in years 10 and 20.

For a 100-MW plant, annual major maintenance expense escalates by inflation to approximately $625,000 in year 10 and $800,000 in year 20 (money of the year). Critics complain that a major maintenance expense is tax-deductible each year. By contrast, their deposit to a reserve fund is not, although once the overhaul is made, the owner can take repair depreciation to shelter income. Because the tax savings from expensing major maintenance does not have a significant impact on COE, and because a consensus estimate for a major maintenance deposit and drawdown schedule is lacking, the program decided to use $5/kW as a reasonable current estimate.

In addition, it is noted that the U.S. Internal Revenue Service (IRS) distinguishes between necessary and ordinary repairs that are expensed and Section 263 improvements that are capitalized (and depreciated), where the improvement increases value of the asset, increases output, or extends its life. In August 2006, the IRS proposed new rules that include a repair allowance method, where the owner of 5-year MACRS property, under which wind energy plants fall, may choose to expense annual repairs running up to 10% of unadjusted basis (initial depreciable base).[1] Although not finalized, these rules offer comfort because combined O&M and major maintenance expense are well below 10%.

Financial Assumptions

For the 1997 DOE/EPRI book, *Renewable Energy Technology Characterizations*, referenced earlier, inflation was estimated at 3%, project life was 30 years, and GenCo financing was 35%/65% debt to equity. The GenCo debt rate, for 28-year debt, was calculated as 30-year Treasuries at 6.5% plus a 1% spread or 7.5%. At 70% debt to 30% equity, IPP debt maturity was 15 years and the IPP rate also referenced off 30-year Treasuries, at 6.5% plus a 1.5% spread or 8%.

Since about 2000, the point of reference became 10-year Treasuries, not 30-year. When the yield curve was steeper, 10-year Treasury rates were about 1% lower, at 5.5%, than 30-year rates. Therefore, the analyst could check 10-year rates and add a 2% spread for GenCos and a 2.5% spread for IPPs. In 2001, Treasury rates were estimated at 5% for 10-year and 6% for 30-year, so debt rates were 7% GenCo and portfolio finance and 7.5% IPP. Later, in 2001, with inflation at 2.5%, and 30-year Treasuries at 5.5%, rates were 6.5% for 28-year GenCo debt, and 7% for 15-year IPP debt, as shown in Table 4. In 2002, at 50% debt to 50% equity, portfolio finance was added, with 22-year debt, calculated as for GenCos, at 6.5%.

At present, inflation is 2.5% and project life is assumed to be 20 years. Debt-to-equity fractions remain the same, but debt terms are 18 years GenCo, and 15 years for IPP and portfolio. It is assumed the bond yield curve is flat. It is assumed 10-year rates are close to 30-year rates but spreads have tightened so BBB-rated debt is about 100 basis points over 10-year Treasuries. Ten-year Treasuries are estimated at 5.5% (This 5.5% rate is higher than the current market at 4.2% in November 2007, but is not grossly out of step with the range of 4% to 5.2%, where 10-year Treasuries have traded from 2005 through late 2007, and it permits spreads to widen slightly.) If one applies spreads of 100 basis points for GenCo and Portfolio and 150 basis points for IPP, one estimates the debt rates shown in Table 8a. These are 6.5% GenCo and Portfolio Finance and 7% for IPP. An underlying theme is that the program does not want to calculate and produce a low COE one year, only to see it rise the next year when technology does not change, but with the increase due only to the fact that interest rates rose. Consequently, the program is conservative (slightly high) in setting interest rates.

Equity return targets, to be met or exceeded, are 13% for GenCo and Portfolio Finance, 17% for IPP, and 11% for All-Equity. Because the developer and early equity investors are at risk to site, finance, and build the plant and market its power, they require a high rate of return. Note that these equity returns are not the (lower-risk) stable return offered to buy-side equity investors who purchase an ownership share after construction is completed and the wind plant is operational. Rather, these equity returns refer to the project's total equity return on all equity investment, which the developer, especially for IPP and All-Equity scenarios, will subdivide into returns for different classes of investment, including shares to sell to later, passive outside equity investors. Note that these are returns to the sell-side project developer, not the buy-side equity investor. The former operate at a higher risk and therefore require a larger return.

Updated financial assumptions for the four ownership/financing scenarios are shown below in Table 8a. Summary descriptions of how and why the parameter values in Table 8a were selected are set forth later,

[1] Federal Register: August 21, 2006; Vol 71, No. 161, pages 48589-48623.

in Table 8b. The updated assumptions in Table 8a apply to plants operating under 2004 business conditions and to those under quick 2006 case assumptions.

Table 8a. Financial Assumptions for Different Financing Structures

	Project (IPP) Finance	Balance Sheet (GenCo)	Portfolio Finance	All-Equity
Lifetime	20 yrs	20 yrs	20 yrs	20 yrs
Inflation	2.5%	2.5%	2.5%	2.5%
Start Year	2005	2005	2005	2005
Construction Period (years)	1.	1	1	1
Debt/Equity	70/30 w/ no PTC 60/40 w/ PTC	35/65	50/50 w/ no PTC 50/50 w/ PTC	0/100
Debt Rate	7%	6.5%	6.5%	n/a
Debt Period	15 yrs	18 yrs	15 yrs	n/a
Debt Rating Level (project must meet this level, whether actually rated or not)	BBB	BBB for project and for company	BBB for project and for pool of projects	n/a
After-tax Leveraged Equity Return	17%	13%	13%	11%
Tax Rate	40% combined federal/state	40% combined federal/state	40% combined federal/state	40% combined federal/state
Debt Coverage	Minimum of 1.5x; average of 1.8x, assuming a strong PPA	Not applicable from lenders' perspective, as they hold claim to all assets; but GenCo management probably wants a minimum of 1.3x	Minimum of 1.6x; average of 2.0x. These are more stringent than under project finance because only *some* of the plants have PPAs. For all merchant plants, debt coverage must be 2.5 times minimum and 3.0x average	n/a
Revenue Escalation Rate	2% assuming 2.5% inflation	2% assuming 2.5% inflation	2% assuming 2.5% inflation	2% assuming 2.5% inflation
Energy Production as Percentage of Expected Production [explained in Table 8b]	100%	100%	100%	100%
Section 45 Production Tax Credit	Not included in wind program COE; considered only for special analyses	Not included in wind program COE; considered only for special analyses	Not included in wind program COE; considered only for special analyses	Not included in wind program COE; considered only for special analyses..
Principal Repayment of Debt	Level mortgage-style; except customized in special cases (e.g., with PTC)	Level mortgage-style	Level mortgage-style; except customized in special cases (e.g., with PTC)	n/a

	Project (IPP) Finance	Balance Sheet (GenCo)	Portfolio Finance	All-Equity
IOU Cost of Capital Discount Rate for COE	8.5 nominal 5.85 constant	8.5 nominal 5.85 constant	8.5 nominal 5.85 constant	8.5 nominal 5.85 constant
Depreciation	5-year MACRS using half-year convention	5-year MACRS using half-year convention	5-year MACRS using half-year convention	5-year MACRS using half-year convention

One may comment upon various points in Table 8a. As shown, GenCo Balance-Sheet Finance assumes a capital structure that is 35% debt to 65% equity. Project (IPP) Finance is more leveraged at 70% debt to 30% equity. Portfolio Finance is between these two, at 50% debt to 50% equity. For its discount rate, as stated in Section 1, the program employs the weighted average cost of capital of a typical IOU that would buy power or would produce competitive power. Given 2.5% inflation, this discount rate is 8.5%, assuming an IOU with 50% debt at 6.5%, 5% preferred stock at 6.3%, and 45% common stock at 11%. The constant-dollar discount rate is 5.85% [1.085/1.025 -1].

Debt coverage standards for GenCos and IPPs hold the same as for the Reference Turbine. Table 8a shows, for the GenCo using balance sheet finance, debt coverage is moot for lenders who hold claim to a broad array of corporate assets, but the company's executive management will want at least 1.3 times coverage. For the IPP using Project Finance, because of the PPA, which guarantees a price for all the plant's output, debt coverage can be somewhat low, at 1.5 times minimum and 1.8 times average. For Portfolio Finance, assuming that some plants in the portfolio have good PPA's, debt coverage is 1.6 times minimum and 2 times average. (These Portfolio Finance debt coverage standards are reduced from 2002, when investment bankers suggested 2 times minimum and 2.5 times average if several plants in the portfolio had good PPAs. In 2002, in the event no plants in the portfolio had PPAs then, to obtain a BBB rating [or at least meet BBB rating standards], debt coverage needed to be higher, at 3 times minimum and 3.5 times average.)

Note that the revenue escalation rate remains at one half percent slower than inflation. In the United States, historically, power prices have escalated slower than inflation. Industry experts forecast the trend would continue. Further, it is noted that some early IPP projects were required by their PPAs to keep a "tracking account," where the developer/owner recorded the difference in tariff received versus "avoided cost" or other price of power, where the developer was required to pay back any excess. With time, some tracking accounts became very large and some projects defaulted and did not pay. Later, during periods of surplus power or when IPPs were bidding against one another to build projects, the IPP that offered an attractive power purchase schedule, as with a slightly reduced tariff escalation rate, was more likely to be selected.

The revenue escalation rate affects debt repayment and return on equity. For a capital-intensive project, repaying a high fraction of fixed-rate debt, as is the case for Project (IPP) Finance, it is conservative to employ slow revenue escalation and not assume a customized, back-loaded principal repayment schedule for debt, where repayment is greatly eased in later years by inflated revenues. Some bankers refuse to accept customized principal repayment schedules and, sometimes for overseas projects, they will ask for level principal payments, which is an old-time traditional utility repayment schedule and which repays debt faster than by a homeowner's level mortgage schedule.

Although the debt to equity fraction is less for GenCos than for IPPs, the same revenue escalation rate is applied for them and the other financing structures. However, the reader should note that the latest forecasts, such as that by DOE's Energy Information Administration, in *Annual Energy Outlook 2007* (DOE/EIA-0383[2007]), no longer see a decline in electricity prices. AEO 2007 states that, from the 2006 price of 8.3 cents/kWh in 2005 dollars, the average delivered power price declines to 7.7 cents/kWh in 2015 and then rises to 8.1 cents/kWh in 2030. In studying recent cases, the analyst might allow power purchase prices to escalate with inflation instead of slower than inflation. Combining this change with a customized debt principal repayment schedule would greatly reduce COE. However, at present, the program is holding with its assumption that electricity revenues escalate at one half percent slower than inflation, which applies to all ownership/financing scenarios.

To perform a cash flow analysis, after setting up the model, with the plant's revenue pattern organized as a year-one price escalating at one half percent less than inflation, one lowers COE until a constraint is reached. For IPPs, the constraints are debt coverage and targeted after-tax, leveraged IRR. As shown in Appendix C, for the wind energy plant under 2004 business conditions, for IPP ownership, the tight constraint is average debt coverage at 1.8 times and actual equity returns are 20% or more. For GenCos at 35% debt, the tight constraint is equity return at 13%.

For informal IPP cases when the Section 45 PTC is added, if the PTC is not monetized, then debt coverage severely limits any reduction in COE, but the PTC means IRR increases significantly. If debt coverage were the tight constraint for the IPP project with no PTC, adding a PTC that is not monetized does nothing to help debt coverage and the COE remains the same. However, the PTC increases after-tax leveraged IRR to on the order of 35% to 45%.

Consequently, if they need to lower tariffs to find a power purchaser, the developer and his banker may restructure the IPP project to use less debt. Instead of 70% debt to 30% equity, an IPP project taking the PTC might use only 60% to 50% debt and the remainder equity. Informally, as stated in Table 8a, the program assumes IPP projects taking the PTC employ a debt fraction of 60% debt to 40% equity. Because debt coverage is not the tight constraint for GenCos, adding the PTC, even if not monetized, permits a flow of return directly to the bottom line of the equity investor, such that the plant's tariff and COE may be directly reduced.

Table 8b below explains how financial assumptions are calculated. Explanations in Table 8b apply to wind energy plants operating under 2004 business conditions and under quick 2006 case assumptions.

Table 8b. Detailed Financial Assumptions for Different Financing Structures

Feature	Description
Lifetime	The program has traditionally used 30-year lifetimes in its assumptions for IPP and GenCo financing. As discussed, the program now recognizes that an assumption of 20 years would be more appropriate, given current industry practice.
Debt/Equity	The proportion of debt varies with project structure and is a key determinant of COE.
Debt Rate	Debt reflects 2.5% inflation. It reflects 10-year Treasuries at 5.5% plus a 1% spread for BBB-rated GenCos and portfolios and a 1.5% spread for IPPs.
Debt Period	Debt period varies. It is two years less than the assumed 20-year project life for GenCos and five years less for IPPs.
Debt Rating	Investment-grade BBB debt is assumed, reflecting a BBB-rated project and, for GenCos, a BBB-rated company.
Equity Return and Tax Rate	Equity return is leveraged, after-tax. It reflects corporate federal tax of 35% and a deductible state tax of 7.69%, for a combined rate of 40% (.35 + .0769 * .65). Further, the equity return is a minimum target, especially with PTC cases when debt coverage is the tight constraint to reducing COE, and equity return composed of cash and tax benefits can be much higher.

Feature	Description
Debt Coverage	Debt coverage is an important issue for wind plant finance. However, because GenCo Balance-Sheet Finance employs a low fraction of debt, GenCo plants show very strong debt coverage. Only for certain special cases using the PTC has GenCo debt coverage proven to be a tight constraint. But even if lenders are not concerned, it is expected that GenCo executive management would require projects to meet minimum debt coverage of about 1.3 times. For IPP and Portfolio Finance projects, and possibly for GenCo projects, the developer/owner can sometimes "monetize" the PTC. As lending institutions become more comfortable with the PTC as a dependable means to reduce tax expense, developers have been able to "monetize" the PTC, and, in effect, convince the bank or other lender to allow cash from PTC-based tax savings to count toward meeting debt coverage requirements. Some developers have been able to associate with a highly-rated equity investor, or parent company affiliate, that is able and willing to guarantee a cash payment from the PTC. An example is that FPL Group Capital unconditionally guaranteed payment of the PTC to FPL Energy National Wind LLC, in connection with their March 2005 wind portfolio finance offering of $365 million of "BBB-"-rated notes and the holding company's related offering of $100 million of "BB-"-rated notes.
Revenue Escalation	For long-term projects including the 2002 Reference Turbine, the program has assumed electricity prices escalate at inflation less one half percent. Sometimes, for near-term special cases, the program has assumed escalation at inflation less one percent. However, for updated 2004 business conditions, the program reverted to the pattern that electricity revenues escalate at inflation less one half percent, which is 2% (2.5% - 0.5%). Because most plant operating expenses escalate at inflation, this is a conservative assumption that slightly squeezes profits.
Principal Repayment Schedule	For most cases, the program assumes level mortgage-style debt repayment. This is similar to the payment schedule for a homeowner with a fixed rate mortgage, where there is one level payment that is composed more of interest to start and more of principal at the end. Other debt repayment options are level principal payment, as once used by traditional utilities, and customized schedules that attempt to match project cash flows. For the latter, one must convince the lender that the customized schedule makes sense and is not an attempt to back-load debt repayment in hopes an indexed power purchase price, say, will rise in later years. Note that with certain special cases run on an informal basis, the program will customize debt repayment for IPP and Portfolio Finance cases that take a monetized PTC, especially over the first 10 years, in order to reduce COE.
Energy Production	The program's assumption that energy production will be at 100% of its projected value (i.e., what is termed P50 – 50% probability of occurring) is explicitly mentioned in Tables 4 and 8a. This is done to differentiate the program's approach to accounting for energy production from the more conservative P90 (90% probability of occurring) approach that the financial community might impose while evaluating a prospective wind project for financing.
Production Tax Credit	As discussed, the program does not include the PTC in its estimates of COE, because the PTC is not a permanent part of the tax code. This assumption is not compatible with the All-Equity cases. With no PTC, it is unlikely passive equity institutional investors would be interested in the wind plant in the first place.
Depreciation	Section 168 of the Tax Code states that wind (and solar) energy plants are considered alternative energy property that can be treated as five-year property under the general depreciation system of MACRS. Further, Tax Regulations Section 1.48-1(e)(1) permits "closely related" structures or other components to be considered as part of the original plant and thus eligible for the same tax treatment. It is assumed all the wind energy plant is 5-year property, but tax counsel might research whether some components (e.g., fencing) must take longer depreciation. In addition, 5-year MACRS depreciation assumes the half-year convention, so annual fractions are: 20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%.
Unleveraged Pretax Equity Return	The program's cash flow model runs a pretax, unleveraged case as a point of comparison. With no PTC, the rate tends to be lower than the leveraged equity return. The minimum acceptable rate of return for that case is about 3%, as would be earned on a money market account at a bank. Most cases easily exceed this requirement, but occasionally it can become the tight constraint for cases including the PTC for Portfolio Finance and GenCos.

Feature	Description
Positive Before-Tax Cash Flow	In similar fashion, the program requires that each year of before-tax cash flow be positive. It must exceed zero. For IPPs, GenCos, and Portfolio Finance projects taking the PTC, this can become the tight constraint.
Phantom Income	Phantom income is negative after-tax cash flow. The program sets a condition for its analysis that projects show no or very little phantom income. In the latter years of debt principal repayment, when debt payments are composed mostly of principal and less of interest, profits are high and taxes are high, and at the same time non-deductible debt principal payments are high, the owner must pay one or the other out of his or her pocket. Phantom income can be "cured" if the project takes on less debt.

Special Production Tax Credit Considerations

Production Tax Credit

The federal Section 45 Production Tax Credit (PTC) was enacted in October 1992 as part of the Energy Policy Act of 1992 (P.L. 102-486). It offers a 10-year, inflation-adjusted 1.5 cent per kWh tax credit to owners of domestic wind energy plants placed in service beginning January 1, 1994. As an after-tax credit, the PTC serves as an offset, to directly reduce the income tax that the taxpayer otherwise owes. It may be carried forward or back, if the taxpayer cannot use it fully. A PTC sometimes contrasts with an Investment Tax Credit (ITC), where investors might receive a one-time credit equal to 10% or some other fraction of capital cost for the year of plant start-up. While the ITC may reward high capital cost, regardless of plant performance, advocates say the PTC sets proper incentives, as it rewards increased power production. Because the PTC is inflation adjusted, its nominal value was $0.018/kWh in 2004, $0.019/kWh in 2005 and 2006, and $0.02/kWh in 2007.

The PTC is important to plant owners because, as a tax credit, it increases their returns and enables them to maintain lower tariffs. Consequently, more wind energy plants are built. Equipment manufacturers, builders, and developers and investors achieve learning curve benefits in hardware and site development. Certain economies of scale are also realized. Some observers hope that the PTC will no longer be needed after it spurs sufficient development and the learning curve, economy of scale, and other benefits are fully realized. Other observers say that a capital-intensive industry that offers no fuel price risk requires continued incentives. There are pros and cons to both arguments.

At the present time, it is important to realize that the Section 45 Production Tax Credit is not permanent to the U.S. Tax Code. When first enacted, it was available to closed-loop biomass and wind energy plants placed in service before July 1, 1999. Since then, the PTC has often lapsed and been retroactively extended for what are typically two-year periods. In particular, legislation was passed on December 17, 1999 (P.L. 106-170), that retroactively extended the PTC till before January 1, 2002; on March 9, 2002 (P.L. 107-147), which retroactively extended the PTC till before January 1, 2004; and on October 22, 2004 (P.L. 108-357), which retroactively extended the PTC till before January 1, 2006. Lapses in availability of the tax credit are difficult for plant developers and builders. Most recently, with enactment of the Energy Policy Act of 2005 (P.L. 109-58), the Section 45 PTC was extended for wind energy plants placed in service before January 1, 2008. With enactment of the Tax Relief and Health Care Act of 2006 (P.L. 109-432) on December 20 2006, it was extended for wind energy plants placed in service before January 1, 2009.

Cases with No PTC

Because the Section 45 PTC is not permanent, the DOE Wind Energy Program and NREL do not include the PTC when preparing cash flow projections and calculating COE. This is a big difference from industry. Wind energy developers and bankers say the PTC is critical and, in certain instances, they would not undertake a wind project without the PTC. It is not just that one project is economically feasible and can sign a PPA with the PTC, but that its tariff would be too high without PTC. Rather, for example, the passive institutional investors who invest in All-Equity deals are in the highest tax brackets, value tax benefits greatly, and are unlikely to be available as investors in wind energy if there were no PTC. Consequently, running a case for these investors without the PTC is not logical.

However, DOE and NREL perform analysis only without the PTC. That said, in order to have a complete comparison, the program will perform analysis for the updated 100-MW wind energy plant, assuming 2004 business conditions, for all four ownership/financing scenarios—GenCo Balance-Sheet, Project (IPP) Finance, Portfolio Finance, and All-Equity. Similar analysis will be performed for the 100-MW wind plant under quick 2006 case assumptions.

Cases with PTC, but No Assistance in Debt Coverage

On an informal basis and to learn current state of affairs, the program occasionally performs cash flow analysis that includes the PTC. There are two PTC efforts - where the PTC does not aid in debt coverage and where with more aggressive accounting, a "monetized" PTC does aid debt coverage.

For the first type, when a cash flow analysis that includes the PTC is performed, the developer will acknowledge that a tax credit offsets income taxes owed. If the taxpayer has suffered business losses and does not owe high taxes, or if tax regulations are changed so the taxpayer does not owe certain taxes, then there is less to offset and part or all of the PTC must be carried forward or back. If the taxpayer does not owe taxes, the PTC does not produce a cash offset that year and cannot be used to pay down debt.

Often, in computing debt coverage, a banker will look at before-tax cash flow versus the total interest payment, including both interest and principal. The banker will not look at positive after-tax cash flow, even when PTCs are shown, because the banker may think after-tax credits are risky. If the wind energy plant's equity investor suffers a business loss and does not owe high taxes, the investor will not need the PTC and will not generate cash from it to repay debt or for other purposes. Therefore, by the traditional, conservative, banker's approach, the PTC or any other tax credits are not "counted" in calculating debt coverage. For this reason, because the developer of Project (IPP) Finance cases taking PTC at 70% debt to 30% equity will find debt coverage is often the “tight” constraint that prevents lowering COE further, but that PTC increases after-tax IRR significantly, that developer will reduce debt to 60%, taking 40% equity. As shown earlier in Table 8a, the program assumes debt/equity for IPP cases taking the PTC is 60/40. For Portfolio Finance cases taking the PTC, the debt/equity fractions remain 50%/50%.

As one additional check, the banker will determine if the after-tax cash flow is negative. If it is, the developer or equity investor has phantom income, which does not offer strong encouragement that later debt payments will be promptly paid. Phantom income arises in later years of debt repayment when the portion of the annual debt payment comprising tax-deductible interest is low, so earnings and income tax are high, but cash is still needed for principal repayment. Reducing the level of debt reduces phantom income.

Cases with Monetized PTC (i.e., full assistance in debt coverage)

Interestingly, over the last couple years, some developers and their tax lawyers have undertaken a more aggressive approach, where they "monetize" the PTC and claim it can be used to repay debt. The lender will agree to this approach only if a large, well-established company will unconditionally guarantee payment of the PTC to equity investors who, in turn, guarantee debt payments to the lender. The entity guaranteeing the PTC must be both able and willing to make a cash payment. For example, FPL Group Capital guaranteed PTC payments to FPL Energy National Wind in connection with their offering of $365 million of notes rated "BBB-" and the holding company's related offering of $100 million of notes rated "BB-", both in February 2005. Critics point out that if a weak entity guarantees the PTC and if problems arise, that plans could fall apart and debt would not be repaid.

To further optimize deal structure, after a creditworthy entity commits to pay the PTC or the PTC tranche of the loan, which reassures lenders, in conjunction, the developer may seek outside equity investors. The developer may offer them a “partnership flip,” so that, in return for their significant equity contribution, they receive a large share of the project’s early returns, flipping to a smaller share later. The IRS recently issued guidelines, as Revenue Procedure 2007-65, dated November 5, 2007, regarding allocations of cash and tax returns among different equity ownership classes when they jointly own one project, including how those allocations may change or flip over time. The IRS Revenue Procedure “establishes the requirements (the Safe Harbor) under which the service will respect the allocation of Section 45 wind energy production tax credits by partnerships in accordance with Section 704(b).”[2]

Consequently, for wind projects, it is sometimes interesting to run the cash flow analysis for the monetized case and to see how low COE and the tariff can be set if PTC is monetized. Note that, to take full advantage and lower COE further, for IPP and Portfolio Finance cases, the debt repayment schedule can be customized, to pay back more debt during the first ten years which coincides with the 10-year PTC.

A Side Case-within-a-Case: Pre-tax, No Debt Analysis

Finally, the conservative developer and his or her banker may perform a side calculation to show project cash flows when there is no debt and no tax, to show that it is not a tax shelter, but has some real economic benefit. The developer/owner wants to know there is economic merit and so do the banker/bondholders, and the equity investors. From time to time, there is an IRS calculation related to this. The program’s model performs this calculation. Specifically, it assumes the tax rate is zero and the debt fraction is zero and, obviously, that the PTC is zero. The program sets a condition for its analysis that the pre-tax unleveraged IRR be greater than about 3%, which is the return a homeowner might earn on a money market account at a bank. While this sort of minimal cash return test was once required by the IRS, that policy is now under review. The program will monitor developments in this area. In the meantime, most cases easily exceed this requirement, but occasionally it can become the tight constraint for cases including the PTC for Portfolio Finance and GenCos.

As described in Table 8b, the program also seeks that each year of before-tax cash flow be positive. It seeks that in the later years of debt repayment, that a project show no or very little "phantom income," which is negative after-tax cash flow. Such problems may sometimes arise for special cases, where IPP or other leveraged plants take the PTC.

Comparative COEs for 2004 Business Conditions

All four ownership/financing scenarios were employed to analyze a 100-MW wind energy plant utilizing 2004 business conditions. To better explore issues, three sets of analysis were performed. Table 9 below shows COEs without the Section 45 PTC, Table 10 shows them with the PTC, and Table 11 shows COEs with a monetized PTC that could be applied to debt coverage.

All COEs are levelized and are expressed in constant 2004 dollars. As shown in Tables 5 and 6, 2004 technology is calculated from an initial capital cost for hardware of $1,260/kW. This compares to $981/kW for 2002 advanced technology, as shown in Table 1. This assumption of increased cost is based on anecdotal evidence that current market conditions, including tight factory capacity and high global demand, have resulted in a short-term increase in cost of turbines. The 100-MW project built under 2004 business conditions has a loaded capital cost that ranges from$1,332 to $1,407 per kW, as shown in Table 6, versus $1,041 to $1,099 per kW for Reference Turbine Technology in Table 2. Further, the 100-MW plant functions under the updated operating expenses shown in Table 7 and the financing assumptions shown in Tables 8a and 8b.

[2] Internal Revenue Bulletin: 2007-45, November 5, 2007, Rev. Proc. 2007-65, U.S. Internal Revenue Service.

Table 9. Cost of Energy Results for 100-MW Wind Plant Employing 2004 Business Conditions Under Different Ownership/Financing Structures (levelized in 2004 dollars, as cents/kWh)

	70/30 Project (IPP) Finance	Balance Sheet (GenCo)	Portfolio Finance	All-Equity
Cost of Energy	6.9	6.4	6.2	7.2

As shown in Table 9, the constant-dollar levelized COE, in 2004 dollars, for GenCo ownership/financing is 6.4 cents/kWh. As stated, this excludes PTC.

The range of results, listed in Table 9, is within about one cent. All-Equity and Project (IPP) Finance are at the high end of the COE range. (It may be somewhat deceptive to include the COE for the All-Equity case in this table, as passive equity tax investors may not be interested in wind plants without the PTC.)

It is important to recognize that the program's COE approaches are all simplified, and thus not reflective of the creative ways that real world financiers and developers would structure deals. There is no attempt to optimize leveraging, for the most part. There is no attempt to employ multiple layers of debt, to show "slicing" of the equity return among different classes of equity investors who receive different portions of benefits that "flip" during the project's lifetime.

COEs with the Production Tax Credit

The federal Section 45 Production Tax Credit can add great complexity to how a project's benefits are distributed. As stated, on August 8, 2005, the Energy Policy Act of 2005 (P.L. 109-58), extended the Section 45 PTC for plants placed in service until before January 1, 2008, and on December 20, 2006, the Tax Relief and Health Care Act of 2006 (P.L. 109-432) extended the PTC for plants in service before January 1, 2009. While industry observers fully expect the PTC to again be extended after that, such extension is not guaranteed.

Although not generally quoted by the program, the PTC can have a significant effect on COE. Table 10 provides estimates of COE for wind energy plants operating under 2004 business conditions with the PTC, but with no assistance by the PTC in debt coverage. Table 11 presents COEs with a monetized PTC that does contribute to debt coverage.

Table 10. Cost of Energy Results for 100 MW Wind Plant employing 2004 Business Conditions, under Different Ownership/Financing Structures with the Production Tax Credit (levelized in 2004 dollars, as cents/kWh)

	60/40 Project (IPP) Finance	Balance Sheet (GenCo)	Portfolio Finance	All-Equity
Cost of Energy	6.2	4.3	5.7	5.1

For the IPP case listed earlier in Table 9, because debt coverage was the tight constraint to reducing COE, including the PTC does nothing to aid debt coverage and does not lower COE if it cannot assist to repay debt. The only effect is to raise after-tax leveraged IRR to 42%. Project structure is unbalanced. Therefore, when PTC is taken by IPPs, as shown in Tables 10 and 11, the IPP debt to equity ratio is revised to 60%/40%. As shown, the IPP's COE declines from 6.9 cents/kWh in Table 9, to 6.2 in Table 10 and 4.9 in Table 11.

In addition, to calculate the cash flows for Table 11, since the PTC is 10 years and the debt period is 15 for IPPs and Portfolio Finance, principal repayment was customized so that more debt was repaid in the first 10 years. The GenCo has a low enough fraction of debt that monetizing the PTC does not matter. The All-Equity case uses no debt, therefore monetizing the PTC does not matter.

Table 11. Cost of Energy Results for 100-MW Wind Plant Employing 2004 Business Conditions Under Different Ownership/Financing Structures with a Monetized Production Tax Credit (levelized in 2004 dollars, as cents/kWh)

	60/40 Project (IPP) Finance	Balance Sheet (GenCo)	Portfolio Finance	All-Equity
Cost of Energy	4.9	4.3	4.4	5.1

Clearly, COEs with PTC are lower than those without. In comparing Tables 10 and 11 to Table 9, it should be noted that the reduction in COE is larger than the PTC itself, except for Portfolio Finance, where it is close. There are two factors at work. First, there is an increase in benefit because a tax credit of 1.8 cents/kWh is equivalent to a per-kWh tariff decrease of 1.9 divided by (1-tax rate), where the combined tax rate is estimated at 40%, which becomes 1.9/0.60, or 3.167 cents per kWh. Second, there is a decrease because the tax credit runs for only 10 years, not the 20-year project life. For a levelized COE, one levelizes over 20 years of project life, with 10 years of PTC and 10 years of nothing.

The reduction between the no-PTC and with-PTC cases is not uniformly the same, due to the different project structure assumptions. For GenCos, the levelized constant-dollar COEs in Tables 10 and 11 are 4.3, which is 2.1 cents lower than the GenCo COE in Table 9. As shown in Appendix C, because equity return was the tight constraint for GenCo, monetizing PTC had little effect and did not enable the COE or tariff to be reduced. (See Appendices F, G, and H for GenCo cases.)

Likewise, for All-Equity, the levelized constant-dollar COEs in Tables 10 and 11 are 5.1, which is 2.1 cents lower than with no PTC in Table 9. Because All-Equity employs no debt, monetizing PTC had no effect. For Project (IPP) Finance and for Portfolio Finance, monetizing the COE had a significant effect as their respective COEs in Table 11 are more than one cent less than in Table 10. (See Appendix C for details and see Appendices I, J, and K for IPP cases.)

Informational COEs for Quick 2006 Case Assumptions

All four ownership/financing scenarios were again employed to analyze a 100-MW wind energy plant utilizing the quick 2006 case assumptions. Results are shown below in Table 12. Appendix D provides a full chart of results, including COEs in 2007 dollars, that corresponds with the plant's start-up year. However, results also were translated into 2004 dollars, to be comparable with results in Tables 9 through 11.

Table 12. Cost of Energy Results for 100-MW Wind Plant Under Quick 2006 Case Assumptions Under Different Ownership/Financing Structures (levelized in 2004 dollars, as cents/kWh)

	Project (IPP) Finance	Balance Sheet (GenCo)	Portfolio Finance	All-Equity
COE with no PTC	7.7	7.2	6.9	8.0
COE with PTC (but no assistance for debt coverage)	6.9	5.1	6.4	6.0
COE with monetized PTC	5.5	5.1	5.0	6.0

As shown, the lowest COEs at 5 and 5.1 cents/kWh in 2004 dollars are achieved by Portfolio Finance and GenCo owners, assuming a monetized PTC. Because GenCo has such low debt, it achieved the same result when PTC is not monetized.

Finally, excluding the PTC, under the program's traditional methodology, the quick 2006 case COEs are 6.9 cents/kWh for Portfolio and 7.2 cents for GenCo. They are higher, at 7.7 cents/kWh for IPPs and 8 cents for All-Equity. When compared to Table 9, with all results in 2004 dollars, these COEs are about three quarters of one cent higher. Clearly, it is better if capital costs are lower.

Market conditions continue to change. To analyze one specific project at a specific location, one must gather specific capital cost and the latest wind performance and operating expense inputs for that site. If specific wind energy plant capital costs are higher than shown in Tables 5 and 6 then, unless capacity factor increases or financing costs decline, it is likely that COEs would be higher than those in Tables 9 though 11. The analyst must consider whether higher costs are temporary or site-specific or reflect an underlying technological or economic change.

Concluding Note

In conclusion, the DOE and NREL Wind Energy Program calculates COE in constant dollars that exclude inflation and as a levelized figure that holds steady over project life. The program assumes GenCo ownership/financing of a typical 100-MW wind energy plant as a simplified means to analyze technology improvements and economic and other trends. By describing capital cost, operating expense, and financial assumptions in this short report, it is hoped that industry and the public may better understand the program's approach. In addition, to obtain the most recent, complete and reliable information, the program encourages feedback regarding assumptions.

Several appendices are included at the end of this report. These include Appendix A, with information about the 2002 Reference Turbine and a simplified fixed charge rate method to calculate COE, and Appendix B, with a short note and graph about shorter project life and three methods to state COE. Appendix C summarizes COE and financial results for various ownership/financing scenarios for the wind energy plant under 2004 business conditions. Appendix D summarizes COE and financial results under quick 2006 case assumptions.

Next are several Financial Appendices that set forth cash flow financials for a 100-MW wind energy plant. Appendix E shows results for the 2002 Reference Turbine as a GenCo with no PTC. The other Appendices cover updated 2004 business conditions. Appendices F, G, and H show GenCo without the PTC, with it, and also with a monetized PTC. On an informal basis, for information's sake, Appendices I, J, and K show Project (IPP) Finance without the PTC, with it, and with a monetized PTC.

Appendices

Appendix A 2002 Reference Turbine COE and that for 2000 Technology, Calculated Using a Fixed Charge Rate

Appendix B Effect of Reducing Project Life and Three Ways to State COE of a Wind Project

Appendix C. Summary of COE and Financial Results for 100-MW Wind Energy Plant Using 2004 Business Conditions

Appendix D. Summary of COE and Financial Results for 100-MW Wind Energy Plant using Quick 2006 Case Assumptions

Appendix A. Year 2002 Reference Turbine COE, and for Year 2000 Technology

For the DOE/NREL Next Generation Low Wind Speed Technology Project, project participants estimate COEs quickly and simply by using a Fixed Charge Rate, instead of lengthy discounted cash flow analysis. The 2002 Constant-dollar Fixed Charge Rate is 11.85%.

Three examples are shown below in Table 13. With only 25.1% as a capacity factor, year 2000 technology produces a constant-dollar levelized COE of 5.94 cents/kWh in 2002 dollars. With 33.8% as a capacity factor, both Examples 2 and 3 of year 2002 technology produce lower COEs, of 4.6 to 4.8 cents/kWh in 2002$.

Example Number 2 is the default case for the Next Generation Low Wind Speed Technology Project. It assumes 3.0% inflation and slightly higher financing costs, from summer and fall of 2001. Two variables are specified in the Statement of Work (i.e., land rent as a fixed number and time-lagged after-tax repair depreciation as 20% of repair depreciation).

Example Number 3 fully reflects the 2002 Reference Turbine. Its total capital costs are shown in Tables 1 and 2, its operating expenses are shown in Table 3, and its financing assumptions from late 2001 are listed in Table 4.

For the Fixed Charge Rate calculations, Table 14 below shows how annual operating expenses were figured. Annual operating expenses are figured as a variable cost and are added as the last component in the Fixed Charge Rate formula.

Table 13. Constant 2002 Dollars Levelized COE by Fixed Charge Rate and by Cash Flow Model

Example Number and Formula	**FCR COE**	**Model COE**
1. Year 2000 Technology		
$\frac{950.00\ \$\ \text{cap cost}}{\text{kW-capac}} * \frac{11.85\%\ \text{fixed charge rate}}{25.10\%\ \text{capacity factor}} * \frac{1}{24*365} * \frac{100\ ¢}{1\ \$} + \frac{0.820\ ¢\ \text{op exp}}{\text{kWh}} =$	$\frac{5.940\ ¢}{\text{kWh}}$	$\frac{5.98\ ¢}{\text{kWh}}$
2. Year 2002 Technology, at 3.0% inflation using old financial assumptions		
$\frac{981.00\ \$\ \text{cap cost}}{\text{kW-capac}} * \frac{11.85\%\ \text{fixed charge rate}}{33.80\%\ \text{capacity factor}} * \frac{1}{24*365} * \frac{100\ ¢}{1\ \$} + \frac{0.733\ ¢\ \text{op exp}}{\text{kWh}} =$	$\frac{4.660\ ¢}{\text{kWh}}$	$\frac{4.80\ ¢}{\text{kWh}}$
3. Year 2002 Technology, at 2.5% inflation using newer financial assumptions		
$\frac{981.00\ \$\ \text{cap cost}}{\text{kW-capac}} * \frac{11.85\%\ \text{fixed charge rate}}{33.80\%\ \text{capacity factor}} * \frac{1}{24*365} * \frac{100\ ¢}{1\ \$} + \frac{0.694\ ¢\ \text{op exp}}{\text{kWh}} =$	$\frac{4.620\ ¢}{\text{kWh}}$	$\frac{4.84\ ¢}{\text{kWh}}$

Table 14. Variable Expenses for FCR Calculations

		#1 2000 Tech		#2 2002 Tech		#3 2002 Tech, 2.5% inflation
Inflation (%)		3.00%		3.00%		2.50%
Combined Tax Rate (%)		40.00%		40.00%		40.00%
Cap Cost ($/kW, 2002$)		950		981		981
Turbine Size (MW)		0.75		1.5		1.5
Number of Turbines		2		1		1
Capacity Factor (%)		25.10%		33.79%		33.79%
Power Production (kWh)		3,298,140		4,440,006		4,440,006
IOU debt fraction		50.00%		50.00%		50.00%
IOU debt rate		7.00%		7.00%		6.50%
IOU preferred fraction		5.00%		5.00%		5.00%
IOU preferred return		6.80%		6.80%		6.30%
IOU common fraction		45.00%		45.00%		45.00%
IOU common return		12.00%		12.00%		11.00%
IOU Before-Tax Cost of Capital						
Or Discount Rate		9.24%		9.24%		8.52%
Discount Rate, rounded		9.25%		9.25%		8.50%
GenCo debt fraction		35.00%		35.00%		35.00%
GenCo debt rate		7.00%		7.00%		6.50%
GenCo equity fraction		65.00%		65.00%		65.00%
GenCo equity return		13.00%		13.00%		13.00%
Depreciation		5-year, half yr convent		5-year, half yr convent		5-year, half yr convent
Revenue Escalation Rate		2.50%		2.50%		2.00%
Expense Escalation Rate		3.00%		3.00%		2.50%
Fixed O&M ($/kW, 2002$)		15.00		20.00		20.00
Variable O&M ($/kWh, 2002$)		0.000		0.000		0.000
All O&M expressed as Variable						
($/kWh)		0.00682		0.00676		0.00676
O&M * [1-tax rate]	60.00%					
($/kWh)		0.00409		0.00405		0.00405
Land Royalty (% revenues)		3.00%		--		--
expressed as $/kW (2002$)		4.07		3.33		3.33
expressed as $/kWh		0.00185		0.00113		0.00113
Land * [1-tax rate]	60.00%					
($/kWh)		0.00111		~~0.00068~~		0.00068
Contract specified Land Exp				0.00108		--

		#1 2000 Tech		#2 2002 Tech		#3 2002 Tech, 2.5% inflation
Major Maintenance as $/kW (2002$)		10.50		10.70		10.08
Calc as levelized constant $/kWh		0.00359		0.00275		0.00268
Less Repair Depreciation *						
time-lagged [1-tax rate]		0.00059		~~0.00059~~		0.00047
Contract specified Aft-tax						
Depreciation	20.00%			0.00055		--
Net Major Maintenance		0.00300		0.00220		0.00221
Total Variable Cost ($/kWh, 2002$)		0.008203		0.007334		0.006943

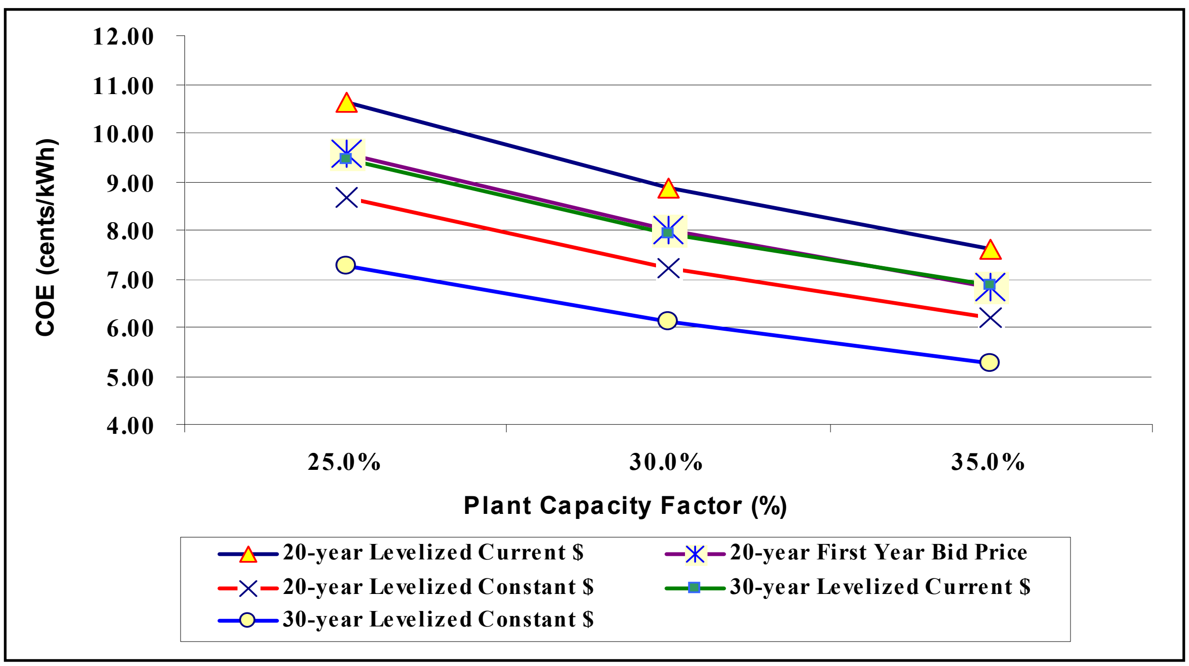
Appendix B. Effect of Reducing Project Life and Three Ways to State COE of a Wind Project

COE can be expressed in several ways. While each of these ways produces a different numerical value for COE, they are all, in fact, comparable representations of the same project. For this reason, it is critical to state how COE was calculated. First, the program does not include the Section 45 PTC because it is not permanent to the Tax Code.

Second, the Wind Energy Program cites a levelized *constant* dollar COE excluding inflation. One may also express COEs in levelized current-dollar or nominal terms or as a first-year bid price (that is not levelized). As shown in Figure B-1 below, current-dollars are highest, first-year bid price is in the middle, and constant dollars are lowest. (In Figure B-1, 20-year first-year bid price closely tracks 30-year levelized current $ COE, so its line does not show clearly.) When capacity factor is lower, COE is higher, and the absolute difference from current dollar to constant dollar is greater.

Furthermore, as discussed, the program changed the assumption for wind plant project life from 30 years to 20 years, to match industry practices. The shorter life means certain costs are spread thicker, therefore COE is higher for 20 years than for 30. At a lower capacity factor, the effect is intensified. For example, for levelized constant-dollar COE at a 25% capacity factor, the 20-year COE is just under 1.5 cents higher than the 30-year COE. At a 35% capacity factor, the 20-year COE is just under 1.0 cent higher than the 30-year COE. These figures are not exact. They show trends, but do not fully reflect program results.

Figure B-1. Comparison of Relative COEs for Wind Energy Plants Without PTC to Illustrate the Range of Values for Different Assumptions.



Appendix C. Summary of COE and Financial Results for 100 MW Wind Energy Plant under 2004 Business Conditions

The 100 MW wind energy plant starts up in January 2005, following a one year construction period. Results with monetized PTC are shown only for IPP, GenCo, and Portfolio Finance. Shaded squares denote the "tight constraint" that prevents tariff from being lowered further.

	IPP No PTC	IPP w/ PTC	IPP w/ Monetized PTC	GenCo No PTC	GenCo w/ PTC	GenCo w/ Monetized PTC	Portfolio No PTC	Portfolio w/ PTC	Portfolio w/ Monetized PTC	All Equity No PTC	All Equity w/ PTC
	Target IRR is 17%; Debt coverage req is 1.80x avg, 1.50x min			*Target IRR is 13%; Debt coverage requirement is 1.30x min.*			*Target IRR is 13%; Debt coverage requirement is 2.00x avg, 1.60x min.*			*Target IRR is 11%.*	
Constant$ COE in 2005$ (¢/kWh)	7.08	6.30	4.98	6.61	4.38	4.38	6.37	5.83	4.46	7.33	5.21
Nominal$ COE in 2005$ (¢/kWh)	8.68	7.73	6.11	8.11	5.37	5.37	7.82	7.15	5.47	8.99	6.39
Year One COE in 2005$ (¢/kWh)	7.53	6.70	5.30	7.03	4.66	4.66	6.78	6.20	4.74	7.80	5.54
Constant$ COE 2004$	6.91	6.15	4.86	6.45	4.27	4.27	6.22	5.69	4.35	7.15	5.08
Nominal$ COE 2004$	8.47	7.54	5.96	7.91	5.24	5.24	7.63	6.98	5.33	8.78	6.23
Debt Coverage (times): average; minimum	1.80; 1.56	1.80; 1.56	1.85; 1.66	4.06; 3.41	2.19; 1.84	2.97; 2.24	2.28; 1.97	2.01; 1.74	2.06; 1.83	--	--
After-tax Leveraged IRR (%)	23.80	28.05	20.07	13.02	13.04	13.04	13.04	21.31	14.04	11.03	11.03
Payback (years)	3	3	4	6	5	5	6	4	5	8	7
Cash-on-Cash (before-tax, non-discounted, excl PTC %): average; minimum	29.91; 14.40	19.22; 9.25	10.66; 1.11	16.73; 12.42	6.88; 4.31	6.88; 4.31	17.75; 10.36	14.75; 7.89	7.54; 1.18	15.65; 12.87	9.68; 7.96
Pre-tax Unlev IRR (%)	12.32	10.12	5.94	11.52	3.92	3.92	10.38	8.73	4.04	13.31	6.78
Pretax, Unlev Paybck (yr)	8	9	13	9	15	15	9	10	15	8	12

	IPP No PTC	IPP w/ PTC	IPP w/ Monetized PTC	GenCo No PTC	GenCo w/ PTC	GenCo w/ Monetized PTC	Portfolio No PTC	Portfolio w/ PTC	Portfolio w/ Mone-tized PTC	All Equity No PTC	All Equity w/ PTC
Loaded Capital Cost ($ Mil)	140.650	140.020	140.020	133.200	133.200	133.200	139.200	139.200	139.200	136.100	136.100
Debt/Equity (%/%)	70/30	60/40	60/40	35/65	35/65	35/65	50/50	50/50	50/50	0/100	0/100
Debt Terms	7.0%, 15 years	7.0%, 15 years	7.0%, 15 years, custom-ized princ pmt	6.5%, 18 years	6.5%, 18 years	6.5%, 18 years	6.5%, 15 years	6.5%, 15 years	6.5%, 15 years, custom-ized princ pmt	--	--

Note – All projects assume 33.8% capacity factor. IPP Debt is limited recourse and secured only by the project. GenCo debt is recourse and secured by the company's balance sheet. Portfolio Finance debt is secured by a diversified pool of projects. All Equity finance includes no debt, but equity is secured only by the one project.

Appendix D. Summary of COE and Financial Results for 100 MW Wind Energy Plant under Quick 2006 Case Assumptions

The 100 MW wind energy plant starts up in January 2007, following a one year construction period. Results with monetized PTC are shown only for IPP, GenCo, and Portfolio Finance. Shaded squares denote the "tight constraint" that prevents tariff from being lowered further. COEs are expressed in year of start-up or 2007 dollars and in 2004 dollars to compare against results in Appendix C.

	IPP No PTC	**IPP w/ PTC**	**IPP w/ Monetized PTC**	**GenCo No PTC**	**GenCo w/ PTC**	**GenCo w/ Monetized PTC**	**Portfolio No PTC**	**Portfolio w/ PTC**	**Portfolio w/ Mone-tized PTC**	**All Equity No PTC**	**All Equity w/ PTC**
	Target IRR is 17%; Debt coverage req is 1.80x avg, 1.50x min			*Target IRR is 13%; Debt coverage requirement is 1.30x min.*			*Target IRR is 13%; Debt coverage requirement is 2.00x avg, 1.60x min.*			*Target IRR is 11%.*	
Constant$ COE in 2007$ (¢/kWh)	8.30	7.38	5.92	7.74	5.51	5.51	7.46	6.86	5.41	8.60	6.45
Nominal$ COE in 2007$ (¢/kWh)	10.18	9.05	7.26	9.49	6.76	6.76	9.16	8.42	6.63	10.55	7.96
Year One COE in 2007$ (¢/kWh)	8.83	7.85	6.30	8.23	5.86	5.86	7.94	7.30	5.75	9.15	6.90
Constant$ COE 2004$	7.71	6.85	5.50	7.18	5.12	5.12	6.93	6.37	5.02	7.99	6.02
Nominal$ COE 2004$	9.46	8.41	6.75	8.81	6.27	6.27	8.50	7.82	6.16	9.80	7.39
Debt Coverage (times): average; minimum	1.80; 1.56	1.81; 1.57	1.82; 1.60	4.06; 3.40	2.49; 2.09	3.15; 2.56	2.28; 1.98	2.03; 1.76	2.13; 1.76	--	--
After-tax Leveraged IRR (%)	23.83	25.93	18.34	13.02	13.03	13.03	13.08	19.74	13.07	11.04	11.06
Payback (years)	3	3	4	6	5	5	6	4	5	8	7
Cash-on-Cash (before-tax, non-discounted, excl PTC %): average; minimum	29.97; 14.40	19.33; 9.31	11.39; 1.95	16.74; 12.40	8.49; 5.61	8.49; 5.61	17.80; 10.38	15.03; 8.10	8.70; 1.87	15.67; 12.87	10.69; 8.77
Pre-tax Unlev IRR (%)	12.33	10.16	6.31	11.51	5.33	5.33	10.40	8.88	4.79	13.32	7.98

	IPP No PTC	IPP w/ PTC	IPP w/ Monetized PTC	GenCo No PTC	GenCo w/ PTC	GenCo w/ Monetized PTC	Portfolio No PTC	Portfolio w/ PTC	Portfolio w/ Mone-tized PTC	All Equity No PTC	All Equity w/ PTC
Pretax, Unlev Paybck (yr)	8	9	12	9	13	13	9	10	14	8	11
Loaded Capital Cost ($ Mil)	167.810	167.010	167.010	159.000	159.000	159.000	166.100	166.100	166.100	162.370	162.370
Debt/Equity (%/%)	70/30	60/40	60/40	35/65	35/65	35/65	50/50	50/50	50/50	0/100	0/100
Debt Terms	7.0%, 15 years	7.0%, 15 years	7.0%, 15 years, custom-ized princ pmt	6.5%, 18 years	6.5%, 18 years	6.5%, 18 years	6.5%, 15 years	6.5%, 15 years	6.5%, 15 years, custom-ized princ pmt	--	--

Note – All projects assume 33.8% capacity factor. IPP Debt is limited recourse and secured only by the project. GenCo debt is recourse and secured by the company's balance sheet. Portfolio Finance debt is secured by a diversified pool of projects. All Equity finance includes no debt, but equity is secured only by the one project.

Financial Appendices
showing cash flows for 100 MW Wind Energy Plant

Appendix E. 2002 Reference Turbine GenCo with no PTC

Appendix F. Updated 2004 Business Conditions GenCo with no PTC

Appendix G. Updated 2004 Business Conditions GenCo with PTC (not monetized)

Appendix H. Updated 2004 Business Conditions GenCo with Monetized PTC

Appendix I. Updated 2004 Business Conditions IPP with no PTC

Appendix J. Updated 2004 Business Conditions IPP with PTC (not monetized)

Appendix K. Updated 2004 Business Conditions IPP with Monetized PTC

SUMMARY PAGE | **100 MW GenCo - 33.8 cf, Class 4, no PTC** | **09/14/06** | **1:39 PM**

File: **RefTurbGenCoWind2002_noPTC.xls**
copies file Sunny 14k

Construction and Development Assumptions and Operating Results
All figures are in thousands of U.S. dollars.

Capital

Total Project Cost	104,044		
Start Date	2003	at 100% for year 1	
Project Description	100 MW Wind Farm, using Class 4 Winds owned by taxable Generating Company using Balance Sheet Finance		

Capital Cost per kW installed capacity: 1,040 [104044 / 100]
Cost per Annual kWh: $0.35 [104044 / 296088]

Finance

Debt	36,415	at 6.500%	for 28 years
Secondary Debt	0	at 8.500%	for 28 years
Equity	67,629		

Total	104,044		

RETURNS

	using a discount rate of	10.00%	for developer
1	Pre-tax Unleveraged IRR	11.468%	over 30 years
	Net Present Value	13,213	using 10%
	Payback	9	years
2	After-tax Leveraged IRR	13.075%	over 30 years Target 13%
	Net Present Value	12,782	using 10%
	Payback	6	years
2a	Cash-on-Cash Return, excluding PTC	17.414%	average
	(before-tax cash on equity, non-discounted)	11.618%	minimum

Operations

Net Rated Capacity	100,000	kW, using	750	kW-rated turbines
Actual Hours/Year	8,760	hours/year	134	turbines
Wind Resource	Class 4 Winds			
Net Capacity Factor	33.80%			
Plant Annual Electricity	296,088.0	thou kWh/year		
Contract Term	30	years		
Operations & Maintenance - fixed	$20.50	/kW or	$15,375	/turbine - year
escalating at	2.50%	/year	equiv to 0.692 c/kWh	
Operations & Maintenance - var.	$0.000	/kWh		
escalating at	2.50%	/year		
For land payment, select 1 = percentage revenues, 2 = fixed rent			2	ok
Site Owner Royalty *not used*	0.00%	of revenues		
Site Owner Land Rent *used*	$341.67	thous/year		
escalating at	2.50%	/year	equiv to 0.115 c/kWh	
Property Tax	1.00%	of depreciable base		
escalating at	0.00%	/year		
where base depreciates	0.00%	/year, till hits	0.0%	
Insurance	1.025%	of depreciable base, esc. at	2.50%	/year
Major Maintenance & Overhauls	$0.00	thous/year or	$0	/turbine - year
escalating at	2.50%	/year	equiv to 0.000 c/kWh	
Inflation	2.50%	/year		
Interest Earned on Reserves	3.00%	/year; Interest on Work. Cap	0.50%	/year

COST OF UTILITY ENERGY

	+---- -->	$0.0535	/kWh - first year
in currency of 2003	+---- -->	$0.0646	/kWh - nominal levelized
	+---- -->	$0.0496	/kWh - constant$ levelized
in currency of the year	+---- -->	$0.0600	/kWh - year 31
in currency of 2002	+---- -->	$0.0630	/kWh - nominal levelized
	+---- -->	**$0.0484**	**/kWh - constant$ levelized**
using a discount rate of		8.50%	nominal
		5.85%	constant (with no inflation)

DEBT COVERAGE -- | | Min Target

Senior Debt Coverage ratio:	5.301	average	-n/a-
	3.970	minimum	(~2.5 - 3.0
Secondary Debt Coverage ratio:	--	average	times for
--	--	minimum	GenCo)

Equipment Overhaul Reserve & Drawdown? yes ok
Every 10 years, at 5 %, 15%, 0% and 0% of plant cost.

01/21/2005 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial incl'g Revenues; pg 5 (Cash Flow): COE disc rate; pg 7 (Debt): PTC details;
pg 9 (Work Sheet #1): depreciation; pg 11 (Work Sheet #2): senior debt; pg 13 (Work Sheet #3): secondary debt.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1. To print, hlt File, Print, Entire Workbook.

This particular Project is 100 MW, using Class 4 Winds winds with a 33.8% capacity factor. Contract term is 30 years.
Capital Cost is $990.94 /kW. O&M is $20.5 /kW and $0 /kWh and $0 thousand per year.

This Project takes NO Production Tax Credit.
Financing is 35% senior debt at 6.5% for 28 years and 0% secondary debt and 65% equity.
Sales Tax is $ 0 thousands. Property tax is 1 % of depreciable base, escalating at 0%, but with base depreciating at 0% per year till hits 0%.

Sources and Uses of Funds **100 MW GenCo - 33.8 cf, Class 4, no PTC** **09/14/06** **1:39 PM**

Uses of Funds *in thousands of mixed-year dollars*

Rotor Assembly		16,502		
Drive Train & Nacelle		37,518		
Controls, Safety System		667		
Tower		6,733		
Market Adjustment				
Foundations, Transport, Roads		11,896		
Assemby, Interconnect, Permits, Engr		13,998		
Permits/Environmental Adjustment				
Manufacturing Uncertainty		10,800		
Construction Contingency		0		
Home Office Overhead (1.0%)		980		--
Total	991 /kW		99,094	*
Sales Tax	0		0	*
Construction Financing	4,950		4,950	*
(estimated as $99.0 mil * 10% * 12 mos * 50% for level draw)				
Construction Insur.			0	*
Land			0	
Initial Working Capital: First Year			0	
Debt Financing Fees	728		0	--
(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)				
Equity Financing Fees	2,029		0	--
(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)				--
Debt Service Reserve Fund	1,428		0	--
Working Capital, Operating Reserve	513		0	
Equipment Repair Reserve Initial Pmt			0	

12/05 note: no debt or eq fin fees & no DSR for GenCo, as included w/ 1% Home Office OH fee			104,044	

Misc.

Start Year	2003
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%

Depreciation Rate #2 5%, 9.5%, 8.55%, 7.7%, 6.93%, 6.23%, 5.9%
5.9%, 5.91%, 5.9%, 5.91%, 5.9%, 5.91%, 5.9%
5.91%, 2.95%, 0%, 0%, 0%, 0%, 0%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

35.00%	Debt	36,415	at 6.500%	for 28 years	level mortgage
0.00%	Second Loan	0	at 8.500%	for 28 years	level mortgage
65.00%	Equity	67,629			
----------		----------		--	
100.00%		104,044		--	
				--	

Taxes

Marginal Tax Rate: Federal		35.00%	corporate federal rate is 35%,
State		7.69%	corporate "average" state is 7.69%,
Combined		40.00%	
Investment Tax Credit		0.00%	

Depreciation *Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.*

Depreciation Class Life #1	5	years; Percent at Life #1	100.00%	ok
Depreciation Class Life #2	15	years; Percent at Life #2	0.00%	ok
Amortization for Equity Finc'g Fees	40.00%	40.00%	20.00%	(See B207 on Sheet2.)

Tax Treatment

Sum of Depreciable Items		104,044	including sales tax		
Primary System Depreciable Base			104,044	5	years
less Tax Credit Adjustmt	50.00%	0			
Primary System Depreciable Base		104,044			
Other Depreciable Base			0	15	years
Amortization over Sr Debt's Life			0	28	years
Amortization over Second Debt's Life			0	28	years
5 years' Amortization			0		
1 years' Amortization			0		
No Write-Off			0		
Land			0		
First Year Start-Up (expensed in yr 1)			0		
Reserve Funds			0		

			104,044	ok	

Revenues

Energy Pmt	$0.0535	/kWh at	2.00%	/year beginning in year	1
Energy Pmt	$0.0600	/kWh at	2.00%	/year beginning in year	31
Capacity Pmt	$0.00	/kWh at	1.00%	/year	

Earnings — **100 MW GenCo - 33.8 cf, Class 4, no PTC** — **09/14/06** — **1:39 PM**

All figures in $thousands.

	0 2002	1 2003	2 2004	3 2005	4 2006	5 2007	6 2008	7 2009	8 2010	9 2011	10 2012
Revenues											
Energy Payment		15,841	16,158	16,481	16,810	17,146	17,489	17,839	18,196	18,560	18,931
Capacity Payment		0	0	0	0	0	0	0	0	0	0
Interest on Reserves		0	19	38	57	75	94	113	132	151	170
Total Revenues		15,841	16,176	16,518	16,867	17,222	17,584	17,952	18,328	18,711	19,101
Operating Costs											
Operations & Maintenance - fixed		2,050	2,101	2,154	2,208	2,263	2,319	2,377	2,437	2,498	2,560
Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
Site Owner Land Rent		342	350	359	368	377	387	396	406	416	427
Property Tax		1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
Insurance		1,066	1,093	1,120	1,148	1,177	1,207	1,237	1,268	1,299	1,332
Major Maintenance & Overhauls		0	0	0	0	0	0	0	0	0	0
Total Operating Costs		4,499	4,585	4,674	4,764	4,858	4,953	5,051	5,151	5,254	5,359
Operating Income		11,342	11,591	11,845	12,102	12,364	12,631	12,901	13,177	13,457	13,742
Other Expenses											
Interest on Loan #1		2,367	2,335	2,301	2,265	2,227	2,186	2,142	2,096	2,046	1,993
Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
Depreciation		20,809	33,294	19,976	11,986	11,986	5,993	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Amortization		0	0	0	0	0	0	0	0	0	0
Total Other Expenses		23,176	35,629	22,278	14,251	14,213	8,179	2,142	2,096	2,046	1,993
Before-Tax Profits		(11,834)	(24,038)	(10,433)	(2,149)	(1,848)	4,452	10,759	11,081	11,411	11,748
40.00% Income Tax Paid (Benefit Rec'd)		(4,733)	(9,615)	(4,173)	(859)	(739)	1,781	4,304	4,432	4,564	4,699
Investment Tax Credit Received		0	0								
Production Tax Credits Received		0	0	0	0	0	0	0	0	0	0
After-Tax Profits		(7,100)	(14,423)	(6,260)	(1,289)	(1,109)	2,671	6,456	6,649	6,846	7,049

Earnings **100 MW GenCo - 33.8 cf, Class 4, no PTC** **09/14/06** **1:39 PM**

All figures in $thousands.

	11	12	13	14	15	16	17	18	19	20	21
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Revenues											
Energy Payment	19,310	19,696	20,090	20,492	20,901	21,320	21,746	22,181	22,624	23,077	23,538
Capacity Payment	0	0	0	0	0	0	0	0	0	0	0
Interest on Reserves	0	72	145	217	289	362	434	506	579	651	0
Total Revenues	19,310	19,768	20,235	20,709	21,191	21,681	22,180	22,687	23,203	23,728	23,538
Operating Costs											
Operations & Maintenance - fixed	2,624	2,690	2,757	2,826	2,897	2,969	3,043	3,119	3,197	3,277	3,359
Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
Site Owner Land Rent	437	448	460	471	483	495	507	520	533	546	560
Property Tax	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
Insurance	1,365	1,399	1,434	1,470	1,507	1,545	1,583	1,623	1,663	1,705	1,748
Major Maintenance & Overhauls	0	0	0	0	0	0	0	0	0	0	0
Total Operating Costs	5,467	5,578	5,691	5,807	5,927	6,049	6,174	6,302	6,434	6,569	6,707
Operating Income	13,843	14,190	14,543	14,901	15,264	15,632	16,006	16,385	16,769	17,159	16,831
Other Expenses											
Interest on Loan #1	1,937	1,878	1,814	1,746	1,674	1,597	1,515	1,428	1,335	1,236	1,131
Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation	628	628	628	628	628	628	628	628	628	628	2,412
Amortization	0	0	0	0	0	0	0	0	0	0	0
Total Other Expenses	2,565	2,505	2,442	2,374	2,302	2,225	2,143	2,056	1,963	1,864	3,542
Before-Tax Profits	11,277	11,685	12,101	12,527	12,962	13,407	13,863	14,329	14,806	15,295	13,289
40.00% Income Tax Paid (Benefit Rec'd)	4,511	4,674	4,841	5,011	5,185	5,363	5,545	5,732	5,923	6,118	5,316
Investment Tax Credit Received											
Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
After-Tax Profits	6,766	7,011	7,261	7,516	7,777	8,044	8,318	8,597	8,884	9,177	7,974

Earnings	100 MW GenCo - 33.8 cf, Class 4, no PTC	09/14/06	1:39 PM								
All figures in $thousands.											
	22	23	24	25	26	27	28	29	30	31	
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Revenues											
Energy Payment	24,009	24,489	24,979	25,479	25,988	26,508	27,038	27,579	28,131	0	
Capacity Payment	0	0	0	0	0	0	0	0	0	0	
Interest on Reserves	0	0	0	0	0	0	0	0	0	0	0
Total Revenues	24,009	24,489	24,979	25,479	25,988	26,508	27,038	27,579	28,131	0	0
Operating Costs											
Operations & Maintenance - fixed	3,443	3,529	3,617	3,708	3,801	3,896	3,993	4,093	4,195	0	
Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	
Site Owner Land Rent	574	588	603	618	633	649	665	682	699	0	0
Property Tax	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	0	
Insurance	1,791	1,836	1,882	1,929	1,977	2,027	2,077	2,129	2,182	0	
Major Maintenance & Overhauls	0	0	0	0	0	0	0	0	0	0	
Total Operating Costs	6,849	6,994	7,143	7,295	7,452	7,612	7,776	7,945	8,117	0	0
Operating Income	17,161	17,496	17,837	18,184	18,537	18,896	19,262	19,635	20,013	0	0
Other Expenses											
Interest on Loan #1	1,018	899	772	636	492	338	174	0	0	0	0
Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0	0	0	0	0	0
Repair Depreciation	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0
Total Other Expenses	3,430	3,311	3,183	3,048	2,903	2,750	2,586	2,412	2,412	0	0
Before-Tax Profits	13,731	14,185	14,653	15,136	15,633	16,147	16,676	17,223	17,602	0	0
40.00% Income Tax Paid (Benefit Rec'd)	5,492	5,674	5,861	6,054	6,253	6,459	6,670	6,889	7,041	0	0
Investment Tax Credit Received											
Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
After-Tax Profits	8,238	8,511	8,792	9,081	9,380	9,688	10,006	10,334	10,561	0	0

Cash Flow & COE

100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 1:39 PM

All figures in $thousands.	0	1	2	3	4	5	6	7	8	9	10
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Before-Tax Profits		(11,834)	(24,038)	(10,433)	(2,149)	(1,848)	4,452	10,759	11,081	11,411	11,748
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		20,809	33,294	19,976	11,986	11,986	5,993	0	0	0	0
Amortization		0	0	0	0	0	0	0	0	0	0
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		20,809	33,294	19,976	11,986	11,986	5,993	0	0	0	0
Subtract Off:											
Loan #1 Principal		490	522	556	592	630	671	715	761	811	863
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		628	628	628	628	628	628	628	628	628	628
Total Subtractions		1,118	1,150	1,184	1,220	1,258	1,299	1,343	1,389	1,439	1,491
Before-Tax Cash		7,857	8,106	8,360	8,617	8,879	9,146	9,417	9,692	9,972	10,257
Taxes Payable (Benefit Received)		(4,733)	(9,615)	(4,173)	(859)	(739)	1,781	4,304	4,432	4,564	4,699
Investment Tax Credit		0	0								
Production Tax Credit		0	0	0	0	0	0	0	0	0	0
After-Tax Cash	(67,629)	12,591	17,722	12,533	9,477	9,619	7,365	5,113	5,259	5,408	5,557
	After-tax IRR		13.075%								
	using starting estimate of			12.000%	.						
	Net Present Value		12,782	, using	10.00%	as discount rate for developer					
	Payback	6									
		1	1	1	1	1	1	0	0	0	0
	Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value						Minimum	11.62%	<-- --	Reset both as years of project	
	of money [and discount factor] and excluding tax credits, tax losses, tax payments)						Average	17.41%			
Before-Tax Cash and Equity Investmen	(67,629)	7,857	8,106	8,360	8,617	8,879	9,146	9,417	9,692	9,972	10,257
BT Cash to Equity Investment (not discounted)		11.62%	11.99%	12.36%	12.74%	13.13%	13.52%	13.92%	14.33%	14.75%	15.17%

		1	2	3	4	5	6	7	8	9	10
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	15,841	16,158	16,481	16,810	17,146	17,489	17,839	18,196	18,560	18,931
	Capacity	0	0	0	0	0	0	0	0	0	0
Total (thousands)		15,841	16,158	16,481	16,810	17,146	17,489	17,839	18,196	18,560	18,931

Net Present Value	205,511	, using	8.500%	<--- SET THIS! Before-tax rate, from utility's cost of capital	
Current $ Levelized	19,123	as Rate * NPV/(1-(1+Rate)^(-n))		(e.g., 5.50% for tax-free coop; 8.5% for IOU) *	
lev COE/kWh	$0.0646	in nominal terms of	2003		04/30/01 note: NPV boosts year 1 to 100% and
lev COE/kWh	$0.0630	in nominal terms of	2002		cuts any N+1 last year to zero.
1st-yr Cost	$0.0535				
Constant $ NPV	205,511	, as nominal			
Constant $ levelized	14,697	, using	5.854%	= (1 + 0.085)/(1 + 0.025) - 1	
lev COE/kWh	$0.0496	in constant terms of	2003		
lev COE/kWh	$0.0484	in constant terms of	2002		

Cash Flow & COE — 100 MW GenCo - 33.8 cf, Class 4, no PTC — 09/14/06 — 1:39 PM

All figures in $thousands.	11 2013	12 2014	13 2015	14 2016	15 2017	16 2018	17 2019	18 2020	19 2021	20 2022	21 2023
Before-Tax Profits	11,277	11,685	12,101	12,527	12,962	13,407	13,863	14,329	14,806	15,295	13,289
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	628	628	628	628	628	628	628	628	628	628	2,412
Amortization	0	0	0	0	0	0	0	0	0	0	0
Released from Reserve	0	0	0	0	0	0	0	0	0	0	0
Total Additions	628	628	628	628	628	628	628	628	628	628	2,412
Subtract Off:											
Loan #1 Principal	920	979	1,043	1,111	1,183	1,260	1,342	1,429	1,522	1,621	1,726
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	0
Total Subtractions	3,331	3,391	3,455	3,522	3,595	3,672	3,753	3,841	3,934	4,032	1,726
Before-Tax Cash	8,574	8,922	9,275	9,633	9,996	10,364	10,737	11,116	11,501	11,891	13,975
Taxes Payable (Benefit Received)	4,511	4,674	4,841	5,011	5,185	5,363	5,545	5,732	5,923	6,118	5,316
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	4,063	4,248	4,434	4,622	4,811	5,001	5,192	5,385	5,578	5,773	8,659
	0	0	0	0	0	0	0	0	0	0	0
:t life varies.											
Before-Tax Cash and Equity Investmen	8,574	8,922	9,275	9,633	9,996	10,364	10,737	11,116	11,501	11,891	13,975
BT Cash to Equity Investment (not disc	12.68%	13.19%	13.71%	14.24%	14.78%	15.32%	15.88%	16.44%	17.01%	17.58%	20.66%
COST OF ENERGY Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues: Energy	19,310	19,696	20,090	20,492	20,901	21,320	21,746	22,181	22,624	23,077	23,538
Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)	19,310	19,696	20,090	20,492	20,901	21,320	21,746	22,181	22,624	23,077	23,538

*To figure Discount rate:

Utility debt	50.00%	6.50%
preferred	5.00%	6.30%
common	45.00%	11.00%

8.52% weighted average cost of capital

Cash Flow & COE

100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 1:39 PM

All figures in $thousands.	22 2024	23 2025	24 2026	25 2027	26 2028	27 2029	28 2030	29 2031	30 2032	31 2033	2034
Before-Tax Profits	13,731	14,185	14,653	15,136	15,633	16,147	16,676	17,223	17,602	0	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0
Released from Reserve	0	0	0	0	0	0	0	0	0	0	0
Total Additions	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	0	0
Subtract Off:											
Loan #1 Principal	1,838	1,958	2,085	2,221	2,365	2,519	2,683	0	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	1,838	1,958	2,085	2,221	2,365	2,519	2,683	0	0	0	0
Before-Tax Cash	14,304	14,639	14,980	15,327	15,680	16,039	16,405	19,635	20,013	0	0
Taxes Payable (Benefit Received)	5,492	5,674	5,861	6,054	6,253	6,459	6,670	6,889	7,041	0	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	8,811	8,965	9,118	9,272	9,427	9,581	9,735	12,745	12,973	0	0
	0	0	0	0	0	0	0	0	0	0	0
Before-Tax Cash and Equity Investmen	14,304	14,639	14,980	15,327	15,680	16,039	16,405	19,635	20,013	0	0
BT Cash to Equity Investment (not discc	21.15%	21.65%	22.15%	22.66%	23.19%	23.72%	24.26%	29.03%	29.59%	0.00%	0.00%
COST OF ENERGY Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%	100%
Electric Revenues: Energy	24,009	24,489	24,979	25,479	25,988	26,508	27,038	27,579	28,131	0	0
Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)	24,009	24,489	24,979	25,479	25,988	26,508	27,038	27,579	28,131	0	

Debt Redemption & PTC 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 1:39 PM

All figures in $thousands.

		0 2002	1 2003	2 2004	3 2005	4 2006	5 2007	6 2008	7 2009	8 2010	9 2011	10 2012
Loan #1		36,415	at 6.500%	for 28 years	level mortgage -- with ONE payment/year							
Beginning Balance			36,415	35,926	35,404	34,848	34,256	33,626	32,955	32,240	31,479	30,668
Interest			2,367	2,335	2,301	2,265	2,227	2,186	2,142	2,096	2,046	1,993
Loan Guarantee Fees			0	0	0	0	0	0	0	0	0	0
Principal			490	522	556	592	630	671	715	761	811	863
Total			2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
Available Cash: Operating Income			11,342	11,591	11,845	12,102	12,364	12,631	12,901	13,177	13,457	13,742
PTC monetization, if any			0	0	0	0	0	0	0	0	0	0
Total Debt Service			2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
Debt Coverage Ratio			3.970	4.057	4.146	4.236	4.328	4.421	4.516	4.612	4.710	4.810
Average Ratio	5.301		not counting last partial year									
Minimum Ratio	3.970											
Loan #2		0	at 8.500%	for 28 years	level mortgage -- with ONE payment/year							
Beginning Balance			0	0	0	0	0	0	0	0	0	0
Interest			0	0	0	0	0	0	0	0	0	0
Principal			0	0	0	0	0	0	0	0	0	0
Total			0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?	yes		, where yes means pay senior debt first or no is pay both loans together.									
Available Cash: Op Income & PTC, if monetized			8,485	8,734	8,988	9,245	9,507	9,774	10,045	10,320	10,600	10,885
Total Debt Service			0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned			#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Minimum Ratio	0.000											

Prod'n Tax Credit 3 — Select 1 = escalating rate by formula or 2 = customized rate or 3 = TURNED OFF for no credit at all. PTC expires 12/31/2007, unless extended.

ok

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1 Escalating Rate		{ Starting Credit	$0.018	/kWh;	Start Year		1		yr 1 fraction	1.000 }		
(enter data on right;		{ Escal Rate	2.500%	year;	Last Year		10			}		
(calc'd rate in line 158;		{								}		
(selected rate in line 163.)		{	5,330	5,463	5,599	5,739	5,883	6,030	6,181	6,335	6,494	6,656
2 Customized Absolute			0	5,330	5,463	5,599	5,739	5,883	6,030	6,181	6,335	6,494
Active Credit:	$/kWh $thous		0	0	0	0	0	0	0	0	0	0

Debt Redemption & PTC 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 1:39 PM

All figures in $thousands.

			11	12	13	14	15	16	17	18	19	20	21
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Loan #1												
	Beginning Balance		29,805	28,885	27,906	26,862	25,752	24,569	23,309	21,967	20,538	19,016	17,395
	Interest		1,937	1,878	1,814	1,746	1,674	1,597	1,515	1,428	1,335	1,236	1,131
	Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
	Principal		920	979	1,043	1,111	1,183	1,260	1,342	1,429	1,522	1,621	1,726
	Total		2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
	Available Cash: Operating Income		13,843	14,190	14,543	14,901	15,264	15,632	16,006	16,385	16,769	17,159	16,831
	PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
	Total Debt Service		2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857	2,857
	Debt Coverage Ratio		4.845	4.967	5.091	5.216	5.343	5.472	5.603	5.735	5.870	6.006	5.892
	Average Ratio	5.301											
	Minimum Ratio	3.970											
	Loan #2												
	Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
	Interest		0	0	0	0	0	0	0	0	0	0	0
	Principal		0	0	0	0	0	0	0	0	0	0	0
	Total		0	0	0	0	0	0	0	0	0	0	0
	Is second loan subordinate?												
	Available Cash: Op Income & PTC, if m		10,986	11,334	11,686	12,044	12,407	12,776	13,149	13,528	13,912	14,302	13,975
	Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
	Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Average Ratio	0.000											
	Minimum Ratio	0.000											
	Times Interest Earned		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
	Minimum Ratio	0.000											
	Prod'n Tax Credit	3											
	ok												
1	Escalating Rate (enter data on right; (calc'd rate in line 158; (selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2	Customized Absolute		6,656	0	0	0	0	0	0	0	0	0	0
	$/kWh												
	Active Credit: $thous		0	0	0	0	0	0	0	0	0	0	0

Debt Redemption & PTC 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 1:39 PM

All figures in $thousands.

		22	23	24	25	26	27	28	29	30	31	
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Loan #1												
Beginning Balance		15,669	13,830	11,872	9,787	7,566	5,201	2,683	0	0	0	0
Interest		1,018	899	772	636	492	338	174	0	0	0	0
Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
Principal		1,838	1,958	2,085	2,221	2,365	2,519	2,683	0	0	0	0
Total		2,857	2,857	2,857	2,857	2,857	2,857	2,857	0	0	0	0
Available Cash: Operating Income		17,161	17,496	17,837	18,184	18,537	18,896	19,262	19,635	20,013	0	0
PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		2,857	2,857	2,857	2,857	2,857	2,857	2,857	0	0	0	0
Debt Coverage Ratio		6.007	6.124	6.243	6.365	6.488	6.614	6.742	0.000	0.000	0.000	0.000
Average Ratio	5.301											
Minimum Ratio	3.970											
Loan #2												
Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?												
Available Cash: Op Income & PTC, if mo		14,304	14,639	14,980	15,327	15,680	16,039	16,405	19,635	20,013	0	0
Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	3											
	ok											
1 Escalating Rate												
(enter data on right;												
(calc'd rate in line 158;												
(selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2 Customized Absolute		0	0	0	0	0						
	$/kWh											
Active Credit:	$thous	0	0	0	0	0	0	0	0	0	0	0

Graph Points — **100 MW GenCo - 33.8 cf, Class 4, no PTC** — **09/14/06** — **1:39 PM**

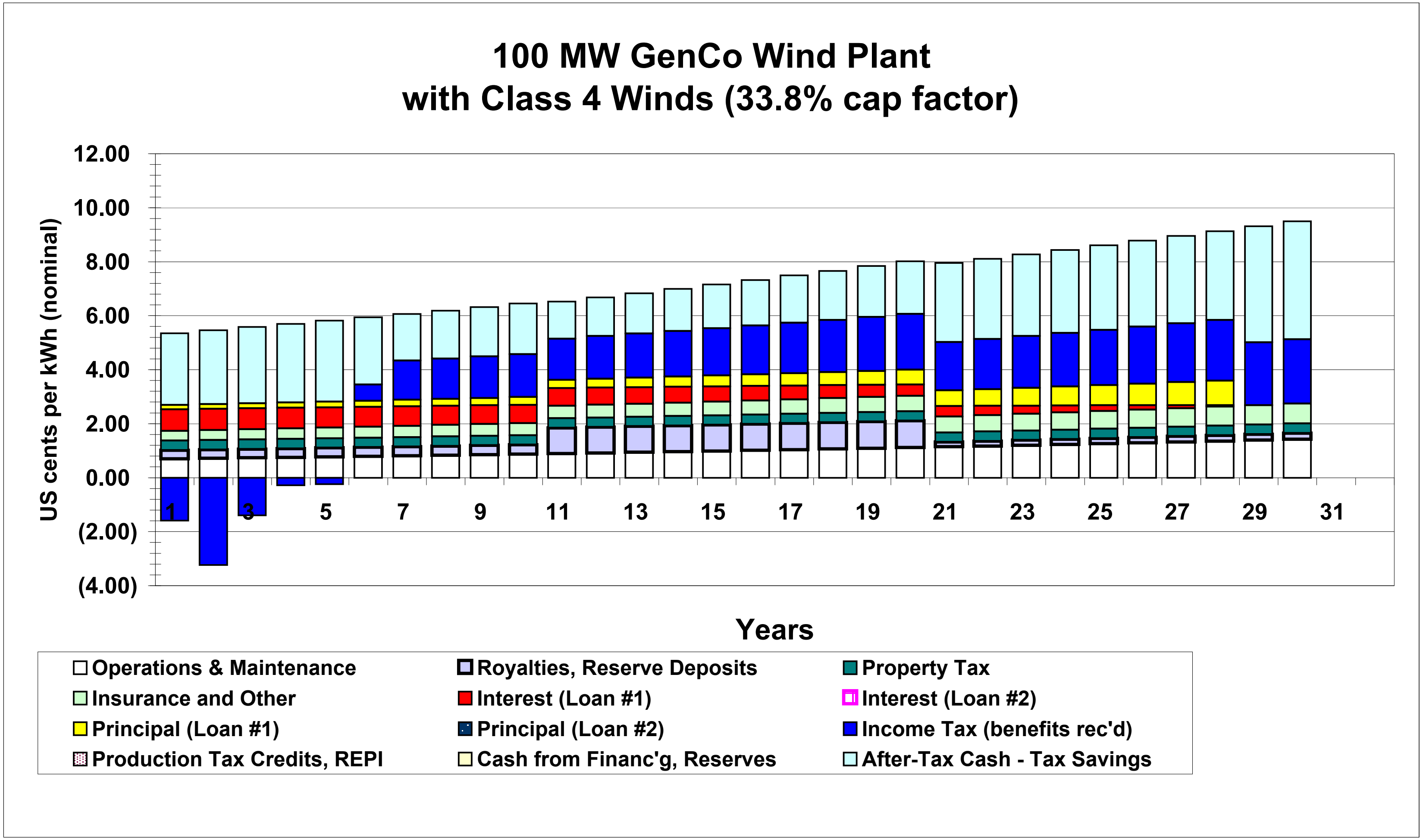
		1	2	3	4	5	6	7	8	9	10
	296,088,000 kWh/year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	Cost Components in nominal US cents/kWh (money of the year)										
	Revenues	5.350	5.463	5.579	5.697	5.816	5.939	6.063	6.190	6.319	6.451
1	Operations & Maintenance	0.692	0.710	0.727	0.746	0.764	0.783	0.803	0.823	0.844	0.865
2	Royalties, Reserve Deposits	0.327	0.330	0.333	0.336	0.339	0.343	0.346	0.349	0.353	0.356
3	Property Tax	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351
4	Insurance and Other	0.360	0.369	0.378	0.388	0.398	0.408	0.418	0.428	0.439	0.450
5	Interest (Loan #1)	0.799	0.789	0.777	0.765	0.752	0.738	0.723	0.708	0.691	0.673
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.165	0.176	0.188	0.200	0.213	0.227	0.241	0.257	0.274	0.292
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	(1.599)	(3.247)	(1.409)	(0.290)	(0.250)	0.601	1.454	1.497	1.542	1.587
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	2.654	2.738	2.823	2.910	2.999	2.487	1.727	1.776	1.826	1.877
	Energy Revenues (with neg tax added as positive)	5.350	5.463	5.579	5.697	5.816	5.939	6.063	6.190	6.319	6.451
check	Energy Revenues	5.350	5.457	5.566	5.677	5.791	5.907	6.025	6.145	6.268	6.394
	Interest on Reserves	0.000	0.006	0.013	0.019	0.025	0.032	0.038	0.045	0.051	0.057
check	Total	5.350	5.463	5.579	5.697	5.816	5.939	6.063	6.190	6.319	6.451

Graph Points 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 1:39 PM

		11	12	13	14	15	16	17	18	19	20	21
	296,088,000 kWh/year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Cost Components											
	in nominal US cents/kWh (money of the											
	Revenues	6.522	6.676	6.834	6.994	7.157	7.323	7.491	7.662	7.837	8.014	7.950
1	Operations & Maintenance	0.886	0.908	0.931	0.954	0.978	1.003	1.028	1.054	1.080	1.107	1.135
2	Royalties, Reserve Deposits	0.962	0.966	0.970	0.974	0.978	0.982	0.986	0.990	0.994	0.999	0.189
3	Property Tax	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351
4	Insurance and Other	0.461	0.473	0.484	0.497	0.509	0.522	0.535	0.548	0.562	0.576	0.590
5	Interest (Loan #1)	0.654	0.634	0.613	0.590	0.565	0.539	0.512	0.482	0.451	0.417	0.382
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.311	0.331	0.352	0.375	0.400	0.426	0.453	0.483	0.514	0.547	0.583
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	1.524	1.579	1.635	1.692	1.751	1.811	1.873	1.936	2.000	2.066	1.795
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	1.372	1.435	1.498	1.561	1.625	1.689	1.754	1.819	1.884	1.950	2.924
	Energy Revenues (with neg tax added as positive)	6.522	6.676	6.834	6.994	7.157	7.323	7.491	7.662	7.837	8.014	7.950
check	Energy Revenues	6.522	6.652	6.785	6.921	7.059	7.200	7.344	7.491	7.641	7.794	7.950
	Interest on Reserves	0.000	0.024	0.049	0.073	0.098	0.122	0.147	0.171	0.195	0.220	0.000
check	Total	6.522	6.676	6.834	6.994	7.157	7.323	7.491	7.662	7.837	8.014	7.950

Graph Points 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 1:39 PM

		22	23	24	25	26	27	28	29	30	31	
296,088,000	kWh/year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Cost Components in nominal US cents/kWh (money of the											
	Revenues	8.109	8.271	8.436	8.605	8.777	8.953	9.132	9.314	9.501	0.000	0.000
1	Operations & Maintenance	1.163	1.192	1.222	1.252	1.284	1.316	1.349	1.382	1.417	0.000	0.000
2	Royalties, Reserve Deposits	0.194	0.199	0.204	0.209	0.214	0.219	0.225	0.230	0.236	0.000	0.000
3	Property Tax	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.351	0.000	0.000
4	Insurance and Other	0.605	0.620	0.636	0.651	0.668	0.684	0.702	0.719	0.737	0.000	0.000
5	Interest (Loan #1)	0.344	0.304	0.261	0.215	0.166	0.114	0.059	0.000	0.000	0.000	0.000
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.621	0.661	0.704	0.750	0.799	0.851	0.906	0.000	0.000	0.000	0.000
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	1.855	1.916	1.980	2.045	2.112	2.181	2.253	2.327	2.378	0.000	0.000
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	2.976	3.028	3.080	3.132	3.184	3.236	3.288	4.305	4.381	0.000	0.000
	Energy Revenues (with neg tax added as positive)	8.109	8.271	8.436	8.605	8.777	8.953	9.132	9.314	9.501	0.000	0.000
check	Energy Revenues	8.109	8.271	8.436	8.605	8.777	8.953	9.132	9.314	9.501	0.000	0.000
	Interest on Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	8.109	8.271	8.436	8.605	8.777	8.953	9.132	9.314	9.501	0.000	0.000


100 MW GenCo Wind Plant
with Class 4 Winds (33.8% cap factor)
US cents per kWh (nominal)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
1
3
5
7
9
11
13
15
17
19
21
23
25
27
29
31
Years
Operations & Maintenance
Royalties, Reserve Deposits
Property Tax
Insurance and Other
Interest (Loan #1)
Interest (Loan #2)
Principal (Loan #1)
Principal (Loan #2)
Income Tax (benefits rec'd)
Production Tax Credits, REPI
Cash from Financ'g, Reserves
After-Tax Cash - Tax Savings

SUMMARY PAGE 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 2:57 PM

File: 0914GenCoWind2004_noPTC.xls

Construction and Development Assumptions and Operating Results

All figures are in thousands of U.S. dollars.

Capital					Capital Cost per kW installed capacity		1,332	[133200 / 100]
Total Project Cost	133,200				Cost per Annual kWh		$0.45	[133200 / 296088]
Start Date	2005	at 100% for year 1						
Project Description	100 MW Wind Farm, using Class 4 Winds owned by taxable Generating Company using Balance Sheet Finance					-- -- --		
Finance					**RETURNS**			
Debt	46,620	at 6.500%	for 18 years		using a discount rate of		10.00%	
Secondary Debt	0	at 7.500%	for 18 years					
Equity	86,580				1 Pre-tax Unleveraged IRR		11.515%	over 20 years
	----------				Net Present Value		13,778	using 10%
Total	133,200				Payback		9	years
					2 After-tax Leveraged IRR		13.022%	over 20 years Target 13%
Operations					Net Present Value		13,081	using 10%
Net Rated Capacity	100,000	kW, using	1,500	kW-rated turbines	Payback		6	years
Actual Hours/Year	8,760	hours/year	67	turbines				
					2a Cash-on-Cash Return, excluding PTC		16.731%	average
Wind Resource	Class 4 Winds				(before-tax cash on equity, non-discounted)		12.415%	minimum
Net Capacity Factor	33.80%							
Plant Annual Electricity	296,088	thou kWh/year			**COST OF UTILITY ENERGY**	+---- -->	$0.0703	/kWh - first year
Contract Term	20	years			in currency of 2005	+---- -->	$0.0811	/kWh - nominal levelized
						+---- -->	$0.0661	/kWh - constant$ levelized
Operations & Maintenance - fixed	20.67	/kW or	$31,005	/turbine - year	in currency of the year	+---- -->	$0.0500	/kWh - year 21
escalating at	2.50%	/year	equiv to 0.698 c/kWh		in currency of 2004	+---- -->	$0.0791	/kWh - nominal levelized
Operations & Maintenance - var.	$0.000	/kWh				+---- -->	$0.0645	/kWh - constant$ levelized
escalating at	2.50%	/year						
For land payment, select 1 = percentage revenues, 2 = fixed rent			2	ok	using a discount rate of	8.50%	nominal	
Site Owner Royalty *not used*	0.00%	of revenues				5.85%	constant (with no inflation)	
Site Owner Land Rent *used*	$333.33	thous/year						
escalating at	2.50%	/year	equiv to 0.113 c/kWh					
Property Tax	1.000%	of depreciable base			**DEBT COVERAGE**	--		Min Target
escalating at	0.00%	/year			Senior Debt Coverage ratio:		4.056	average -n/a-
where base depreciates	0.00%	/year, till hits	0.0%				3.405	minimum 1.30 times
Insurance	1.025%	of depreciable base, esc. at	2.50%	/year	Secondary Debt Coverage ratio:		--	average
Major Maintenance & Overhauls	$500.00	thous/year or	$7,500	/turbine - year	--		--	minimum
escalating at	2.50%	/year	equiv to 0.169 c/kWh					
			--					
Inflation	2.50%	/year			Equipment Overhaul Reserve & Drawdown?	no, not undertaken		ok
Interest Earned on Reserves	3.00%	/year; Interest on Work. Cap	0.50%	/year	Every 10 years, at 0 %, 0%, 0% and 0% of plant cost.			

01/21/2005 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial incl'g Revenues; pg 5 (Cash Flow): COE disc rate; pg 7 (Debt): PTC details;
pg 9 (Work Sheet #1): depreciation; pg 11 (Work Sheet #2): senior debt; pg 13 (Work Sheet #3): secondary debt.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100 MW, using Class 4 Winds winds with a 33.8% capacity factor. Contract term is 20 years.
Capital Cost is $1272 /kW. O&M is $20.67 /kW and $0 /kWh and $500 thousand per year.

This Project takes NO Production Tax Credit.
Financing is 35% senior debt at 6.5% for 18 years and 0% secondary debt and 65% equity.
Sales Tax is $ 0 thousands. Property tax is 1 % of depreciable base, escalating at inflation, but with base depreciating at 0% per year till hits 0%.

Appendix F (cont.)

Sources and Uses of Funds **100 MW GenCo - 33.8 cf, Class 4, no PTC** **09/14/06** **2:57 PM**

Uses of Funds *in thousands of mixed-year dollars*

	Rotor Assembly		16,502		
	Drive Train & Nacelle		37,518		
	Controls, Safety System		667		
	Tower		6,733		
	Market Adjustment		20,000		
	Foundations, Transport, Roads		11,896		
	Assembly, Interconnect, Permits, Engr		13,998		
	Permit/Environmental Adjustment		1,886		
	Manufacturing Uncertainty		10,800		
6,000	Construction Contingency		6,000		
	Home Office Overhead		1,200		--
	Total	1,272 /kW		127,200	*
	Sales Tax	0		0	*
	Construction Financing	6,000		6,000	*
	(estimated as $120 mil * 10% * 12 mos * 50% for level draw)				
	Construction Insur.			0	*
	Land			0	
	Initial Working Capital: First Year			0	
	Debt Financing Fees	932		0	--
	(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)				
	Equity Financing Fees	2,597		0	--
	(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)				--
	Debt Service Reserve Fund	2,234		0	--
	Working Capital, Operating Reserve	517		0	
	Equipment Repair Reserve Initial Pmt			0	

				133,200	

Misc.

Start Year	2005
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%

Depreciation Rate #2 5%, 9.5%, 8.55%, 7.7%, 6.93%, 6.23%, 5.9%
5.9%, 5.91%, 5.9%, 5.91%, 5.9%, 5.91%, 5.9%
5.91%, 2.95%, 0%, 0%, 0%, 0%, 0%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

35.00%	Debt	46,620	at 6.500%	for 18 years	level mortgage
0.00%	Second Loan	0	at 7.500%	for 18 years	level mortgage
65.00%	Equity	86,580			
----------		----------		--	
100.00%		133,200		--	
				--	

Taxes

Marginal Tax Rate:	Federal	35.00%	corporate federal rate is 35%,
	State	7.69%	corporate "average" state is 7.69%,
	Combined	40.00%	
Investment Tax Credit		0.00%	

Depreciation *Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.*

Depreciation Class Life #1	5	years; Percent at Life #1		100.00%	ok
Depreciation Class Life #2	15	years; Percent at Life #2		0.00%	ok
Amortization for Equity Finc'g Fees	40.00%		40.00%	20.00%	(See B207 on Sheet2.)

Tax Treatment

Sum of Depreciable Items		133,200	including sales tax		
Primary System Depreciable Base			133,200	5	years
less Tax Credit Adjustmt	50.00%	0			
Primary System Depreciable Base		133,200			
Other Depreciable Base			0	15	years
Amortization over Sr Debt's Life			0	18	years
Amortization over Second Debt's Life			0	18	years
5 years' Amortization			0		
1 years' Amortization			0		
No Write-Off			0		
Land			0		
First Year Start-Up (expensed in yr 1)			0		
Reserve Funds			0		

			133,200	ok	

Revenues

Energy Pmt	$0.0703	/kWh at	2.00%	/year beginning in year	1
Energy Pmt	$0.0500	/kWh at	2.00%	/year beginning in year	21
Capacity Pmt	$0.00	/kWh at	1.00%	/year	

Earnings

100 MW GenCo - 33.8 cf, Class 4, no PTC **09/14/06** **2:57 PM**

All figures in $thousands.

	0	1	2	3	4	5	6	7	8	9	10
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Revenues											
Energy Payment		20,815	21,231	21,656	22,089	22,531	22,981	23,441	23,910	24,388	24,876
Capacity Payment		0	0	0	0	0	0	0	0	0	0
Interest on Reserves		0	0	0	0	0	0	0	0	0	0
Total Revenues		20,815	21,231	21,656	22,089	22,531	22,981	23,441	23,910	24,388	24,876
Operating Costs											
Operations & Maintenance - fixed		2,067	2,119	2,172	2,226	2,282	2,339	2,397	2,457	2,518	2,581
Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
Site Owner Land Rent		333	342	350	359	368	377	387	396	406	416
Property Tax		1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332
Insurance		1,365	1,399	1,434	1,470	1,507	1,545	1,583	1,623	1,663	1,705
Major Maintenance & Overhauls		500	513	525	538	552	566	580	594	609	624
Total Operating Costs		5,598	5,704	5,814	5,926	6,040	6,158	6,279	6,402	6,529	6,659
Operating Income		15,217	15,527	15,842	16,163	16,490	16,823	17,162	17,507	17,859	18,217
Other Expenses											
Interest on Loan #1		3,030	2,937	2,837	2,731	2,618	2,498	2,370	2,233	2,088	1,933
Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
Depreciation		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Amortization		0	0	0	0	0	0	0	0	0	0
Total Other Expenses		29,670	45,561	28,412	18,076	17,963	10,170	2,370	2,233	2,088	1,933
Before-Tax Profits		(14,453)	(30,034)	(12,569)	(1,912)	(1,473)	6,653	14,792	15,274	15,771	16,283
40.00% Income Tax Paid (Benefit Rec'd)		(5,781)	(12,014)	(5,028)	(765)	(589)	2,661	5,917	6,110	6,308	6,513
Investment Tax Credit Received		0	0								
Production Tax Credits Received		0	0	0	0	0	0	0	0	0	0
After-Tax Profits		(8,672)	(18,020)	(7,542)	(1,147)	(884)	3,992	8,875	9,164	9,462	9,770

Earnings 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 2:57 PM

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Revenues											
	Energy Payment	25,373	25,881	26,398	26,926	27,465	28,014	28,575	29,146	29,729	30,324	0
	Capacity Payment	0	0	0	0	0	0	0	0	0	0	0
	Interest on Reserves	0	0	0	0	0	0	0	0	0	0	0
	Total Revenues	25,373	25,881	26,398	26,926	27,465	28,014	28,575	29,146	29,729	30,324	0
	Operating Costs											
	Operations & Maintenance - fixed	2,646	2,712	2,780	2,849	2,921	2,994	3,068	3,145	3,224	3,304	0
	Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent	427	437	448	460	471	483	495	507	520	533	0
	Property Tax	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	0
	Insurance	1,748	1,791	1,836	1,882	1,929	1,977	2,027	2,077	2,129	2,183	0
	Major Maintenance & Overhauls	640	656	672	689	706	724	742	761	780	799	0
	Total Operating Costs	6,792	6,929	7,069	7,212	7,359	7,510	7,664	7,823	7,985	8,151	0
	Operating Income	18,581	18,952	19,330	19,714	20,106	20,504	20,910	21,323	21,744	22,172	0
	Other Expenses											
	Interest on Loan #1	1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
	Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
	Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Amortization	0	0	0	0	0	0	0	0	0	0	0
	Total Other Expenses	1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
	Before-Tax Profits	16,812	17,359	17,923	18,507	19,111	19,735	20,381	21,051	21,744	22,172	0
40.00%	Income Tax Paid (Benefit Rec'd)	6,725	6,944	7,169	7,403	7,644	7,894	8,153	8,420	8,698	8,869	0
	Investment Tax Credit Received											
	Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits	10,087	10,415	10,754	11,104	11,466	11,841	12,229	12,630	13,046	13,303	0

Cash Flow & COE

100 MW GenCo - 33.8 cf, Class 4, no PTC **09/14/06** **2:57 PM**

All figures in $thousands.	0 2004	1 2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012	9 2013	10 2014
Before-Tax Profits		(14,453)	(30,034)	(12,569)	(1,912)	(1,473)	6,653	14,792	15,274	15,771	16,283
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
Amortization		0	0	0	0	0	0	0	0	0	0
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
Subtract Off:											
Loan #1 Principal		1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Before-Tax Cash		10,749	11,058	11,374	11,695	12,022	12,355	12,693	13,039	13,390	13,748
Taxes Payable (Benefit Received)		(5,781)	(12,014)	(5,028)	(765)	(589)	2,661	5,917	6,110	6,308	6,513
Investment Tax Credit		0	0								
Production Tax Credit		0	0	0	0	0	0	0	0	0	0
After-Tax Cash	(86,580)	16,530	23,072	16,401	12,460	12,611	9,693	6,777	6,929	7,082	7,235

After-tax IRR 13.022%
using starting estimate of 12.000% .
Net Present Value 13,081 , using 10.00% as discount rate for developer
Payback 6

		1	1	1	1	1	1	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value Minimum 12.41% <-- -- Reset both as years of project
of money [and discount factor] and excluding tax credits, tax losses, tax payments) Average 16.73%

Before-Tax Cash and Equity Investmen	(86,580)	10,749	11,058	11,374	11,695	12,022	12,355	12,693	13,039	13,390	13,748
BT Cash to Equity Investment (not discounted)		12.41%	12.77%	13.14%	13.51%	13.88%	14.27%	14.66%	15.06%	15.47%	15.88%

COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	20,815	21,231	21,656	22,089	22,531	22,981	23,441	23,910	24,388	24,876
	Capacity	0	0	0	0	0	0	0	0	0	0
Total (thousands)		20,815	21,231	21,656	22,089	22,531	22,981	23,441	23,910	24,388	24,876

Net Present Value 227,147 , using 8.500% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 24,003 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 5.50% for tax-free coop; 8.5% for IOU) *

lev COE/kWh $0.0811 in nominal terms of 2005 04/30/01 note: NPV boosts year 1 to 100% and
lev COE/kWh $0.0791 in nominal terms of 2004 cuts any N+1 last year to zero.

1st-yr Cost $0.0703
Constant $ NPV 227,147 , as nominal
Constant $ levelized 19,569 , using 5.854% = (1 + 0.085)/(1 + 0.025) - 1
lev COE/kWh $0.0661 in constant terms of 2005
lev COE/kWh $0.0645 in constant terms of 2004

Cash Flow & COE 100 MW GenCo - 33.8 cf, Class 4, no PTC 09/14/06 2:57 PM

All figures in $thousands.	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020	17 2021	18 2022	19 2023	20 2024	21 2025
Before-Tax Profits	16,812	17,359	17,923	18,507	19,111	19,735	20,381	21,051	21,744	22,172	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0
Released from Reserve	0	0	0	0	0	0	0	0	0	0	0
Total Additions	0	0	0	0	0	0	0	0	0	0	0
Subtract Off:											
Loan #1 Principal	2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Before-Tax Cash	14,112	14,483	14,861	15,245	15,637	16,036	16,441	16,855	21,744	22,172	0
Taxes Payable (Benefit Received)	6,725	6,944	7,169	7,403	7,644	7,894	8,153	8,420	8,698	8,869	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	7,387	7,540	7,692	7,843	7,993	8,142	8,289	8,434	13,046	13,303	0
	0	0	0	0	0	0	0	0	0	0	0
:t life varies.											
Before-Tax Cash and Equity Investmen	14,112	14,483	14,861	15,245	15,637	16,036	16,441	16,855	21,744	22,172	0
BT Cash to Equity Investment (not disc	16.30%	16.73%	17.16%	17.61%	18.06%	18.52%	18.99%	19.47%	25.11%	25.61%	0.00%

		11	12	13	14	15	16	17	18	19	20	21
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%
Electric Revenues:	Energy	25,373	25,881	26,398	26,926	27,465	28,014	28,575	29,146	29,729	30,324	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)		25,373	25,881	26,398	26,926	27,465	28,014	28,575	29,146	29,729	30,324	0

*To figure Discount rate:

Utility debt	50.00%	6.50%
preferred	5.00%	6.30%
common	45.00%	11.00%

8.52% weighted average cost of capital

Debt Redemption & PTC | **100 MW GenCo - 33.8 cf, Class 4, no PTC** | **09/14/06** | **2:57 PM**

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Loan #1		46,620	at 6.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			46,620	45,182	43,650	42,018	40,281	38,430	36,459	34,360	32,125	29,744
Interest			3,030	2,937	2,837	2,731	2,618	2,498	2,370	2,233	2,088	1,933
Loan Guarantee Fees			0	0	0	0	0	0	0	0	0	0
Principal			1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Total			4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469
Available Cash: Operating Income			15,217	15,527	15,842	16,163	16,490	16,823	17,162	17,507	17,859	18,217
PTC monetization, if any			0	0	0	0	0	0	0	0	0	0
Total Debt Service			4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469
Debt Coverage Ratio			3.405	3.475	3.545	3.617	3.690	3.765	3.841	3.918	3.996	4.076
Average Ratio	4.056		not counting last partial year									
Minimum Ratio	3.405											
Loan #2		0	at 7.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			0	0	0	0	0	0	0	0	0	0
Interest			0	0	0	0	0	0	0	0	0	0
Principal			0	0	0	0	0	0	0	0	0	0
Total			0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?	yes		, where yes means pay senior debt first or no is pay both loans together.									
Available Cash: Op Income & PTC, if monetized			10,749	11,058	11,374	11,695	12,022	12,355	12,693	13,039	13,390	13,748
Total Debt Service			0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	3		Select 1 = escalating rate by formula or 2 = customized rate or 3 = TURNED OFF for no credit at all.							PTC expires 12/31/2007, unless extended.		
	ok											
1 Escalating Rate		{	Starting Credit	$0.019 /kWh;	Start Year		1		yr 1 fraction	1.000 }		
(enter data on right;		{	Escal Rate	2.500% year;	Last Year		10			}		
(calc'd rate in line 158;		{								}		
(selected rate in line 163.)		{	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687 }	6,854	7,026
2 Customized Absolute			0	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854
	$/kWh											
Active Credit:	$thous		0	0	0	0	0	0	0	0	0	0

Debt Redemption & PTC **100 MW GenCo - 33.8 cf, Class 4, no PTC** **09/14/06** **2:57 PM**

All figures in $thousands.

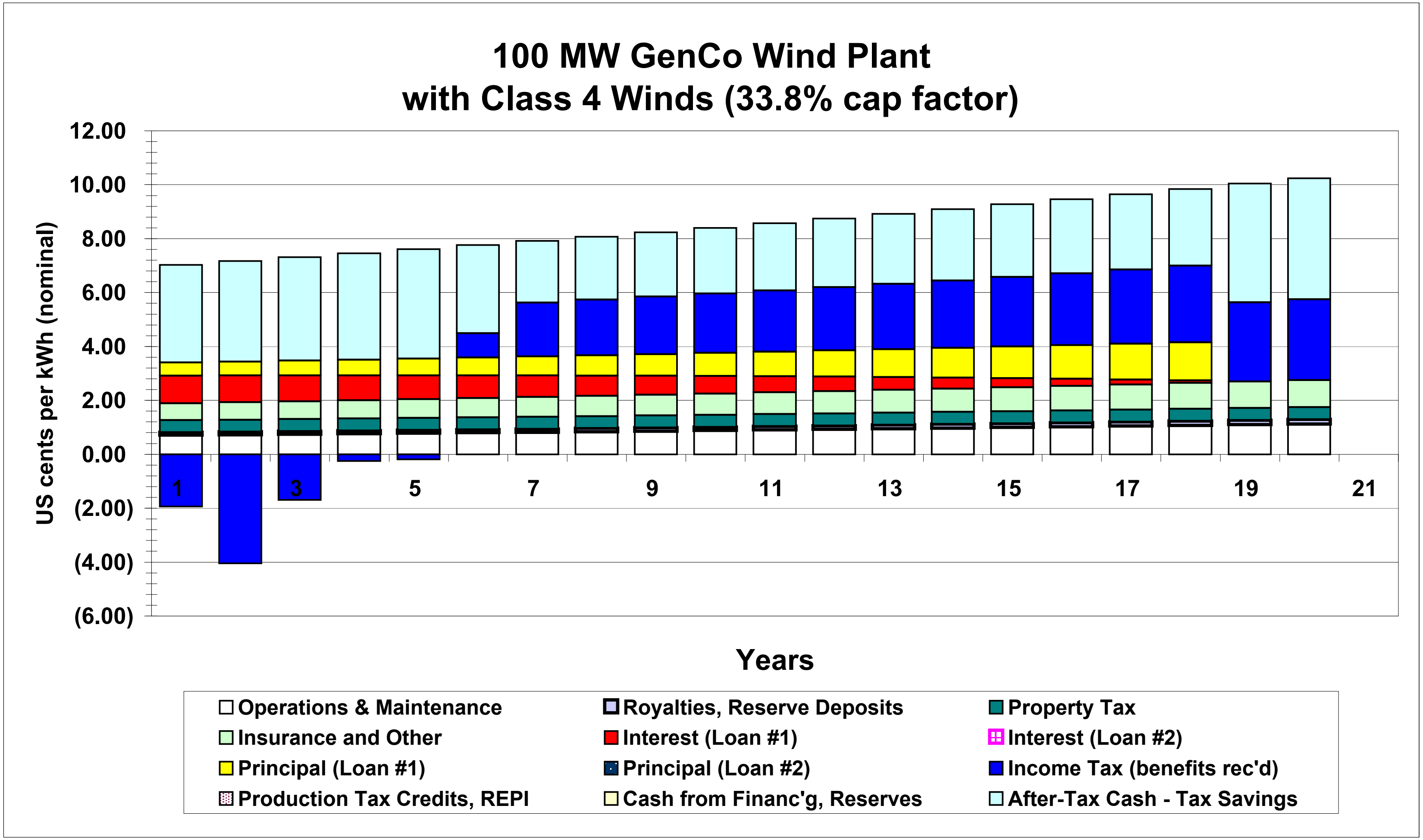
		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Loan #1												
Beginning Balance		27,209	24,509	21,633	18,571	15,309	11,835	8,136	4,196	0	0	0
Interest		1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
Principal		2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Total		4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	0	0	0
Available Cash: Operating Income		18,581	18,952	19,330	19,714	20,106	20,504	20,910	21,323	21,744	22,172	0
PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	0	0	0
Debt Coverage Ratio		4.158	4.241	4.326	4.412	4.499	4.588	4.679	4.772	0.000	0.000	0.000
Average Ratio	4.056											
Minimum Ratio	3.405											
Loan #2												
Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?												
Available Cash: Op Income & PTC, if mo		14,112	14,483	14,861	15,245	15,637	16,036	16,441	16,855	21,744	22,172	0
Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	3											
ok												
1 Escalating Rate (enter data on right; (calc'd rate in line 158; (selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2 Customized Absolute		7,026	0	0	0	0	0	0	0	0	0	0
	$/kWh											
Active Credit:	$thous	0	0	0	0	0	0	0	0	0	0	0

Graph Points **100 MW GenCo - 33.8 cf, Class 4, no PTC** **09/14/06** **2:57 PM**

		1	2	3	4	5	6	7	8	9	10
	296,088,000 kWh/year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Cost Components in nominal US cents/kWh (money of the year)										
	Revenues	7.030	7.171	7.314	7.460	7.609	7.762	7.917	8.075	8.237	8.402
1	Operations & Maintenance	0.698	0.716	0.733	0.752	0.771	0.790	0.810	0.830	0.851	0.872
2	Royalties, Reserve Deposits	0.113	0.115	0.118	0.121	0.124	0.127	0.131	0.134	0.137	0.141
3	Property Tax	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450
4	Insurance and Other	0.630	0.646	0.662	0.678	0.695	0.713	0.731	0.749	0.768	0.787
5	Interest (Loan #1)	1.023	0.992	0.958	0.922	0.884	0.844	0.800	0.754	0.705	0.653
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.486	0.517	0.551	0.587	0.625	0.666	0.709	0.755	0.804	0.856
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	(1.953)	(4.057)	(1.698)	(0.258)	(0.199)	0.899	1.998	2.063	2.131	2.200
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	3.630	3.735	3.841	3.950	4.060	3.274	2.289	2.340	2.392	2.443
	Energy Revenues (with neg tax added as positive)	7.030	7.171	7.314	7.460	7.609	7.762	7.917	8.075	8.237	8.402
check	Energy Revenues	7.030	7.171	7.314	7.460	7.609	7.762	7.917	8.075	8.237	8.402
	Interest on Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	7.030	7.171	7.314	7.460	7.609	7.762	7.917	8.075	8.237	8.402

Graph Points | **100 MW GenCo - 33.8 cf, Class 4, no PTC** | **09/14/06** | **2:57 PM**

			11	12	13	14	15	16	17	18	19	20	21
	296,088,000	kWh/year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Cost Components in nominal US cents/kWh (money of the												
	Revenues		8.570	8.741	8.916	9.094	9.276	9.461	9.651	9.844	10.041	10.241	0.000
1	Operations & Maintenance		0.894	0.916	0.939	0.962	0.986	1.011	1.036	1.062	1.089	1.116	0.000
2	Royalties, Reserve Deposits		0.144	0.148	0.151	0.155	0.159	0.163	0.167	0.171	0.176	0.180	0.000
3	Property Tax		0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.000
4	Insurance and Other		0.806	0.827	0.847	0.868	0.890	0.912	0.935	0.959	0.983	1.007	0.000
5	Interest (Loan #1)		0.597	0.538	0.475	0.408	0.336	0.260	0.179	0.092	0.000	0.000	0.000
6	Interest (Loan #2)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)		0.912	0.971	1.034	1.102	1.173	1.249	1.331	1.417	0.000	0.000	0.000
8	Principal (Loan #2)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)		2.271	2.345	2.421	2.500	2.582	2.666	2.753	2.844	2.938	2.995	0.000
10	Production Tax Credits, REPI		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings		2.495	2.546	2.598	2.649	2.699	2.750	2.799	2.849	4.406	4.493	0.000
	Energy Revenues (with neg tax added as positive)		8.570	8.741	8.916	9.094	9.276	9.461	9.651	9.844	10.041	10.241	0.000
check	Energy Revenues		8.570	8.741	8.916	9.094	9.276	9.461	9.651	9.844	10.041	10.241	0.000
	Interest on Reserves		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
check	Total		8.570	8.741	8.916	9.094	9.276	9.461	9.651	9.844	10.041	10.241	0.000


100 MW GenCo Wind Plant
with Class 4 Winds (33.8% cap factor)
US cents per kWh (nominal)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
1
3
5
7
9
11
13
15
17
19
21
Years
Operations & Maintenance
Royalties, Reserve Deposits
Property Tax
Insurance and Other
Interest (Loan #1)
Interest (Loan #2)
Principal (Loan #1)
Principal (Loan #2)
Income Tax (benefits rec'd)
Production Tax Credits, REPI
Cash from Financ'g, Reserves
After-Tax Cash - Tax Savings

SUMMARY PAGE

100 MW GenCo - 33.8 cf, Class 4, w/ PTC **09/14/06** **4:56 PM**

File: 0914GenCoWind2004_withPTC.xls

Construction and Development Assumptions and Operating Results

All figures are in thousands of U.S. dollars.

Capital

Total Project Cost	133,200		
Start Date	2005	at 100% for year 1	
Project Description	100 MW Wind Farm, using Class 4 Winds owned by taxable Generating Company using Balance Sheet Finance		

Finance

Debt	46,620	at 6.500%	for 18 years
Secondary Debt	0	at 7.500%	for 18 years
Equity	86,580		

Total	133,200		

Operations

Net Rated Capacity	100,000	kW, using	1,500	kW-rated turbines
Actual Hours/Year	8,760	hours/year	67	turbines
Wind Resource	Class 4 Winds			
Net Capacity Factor	33.80%			
Plant Annual Electricity	296,088	thou kWh/year		
Contract Term	20	years		
Operations & Maintenance - fixed	20.67	/kW or	$31,005	/turbine - year
escalating at	2.50%	/year	equiv to 0.698 c/kWh	
Operations & Maintenance - var.	$0.000	/kWh		
escalating at	2.50%	/year		
For land payment, select 1 = percentage revenues, 2 = fixed rent			2	ok
Site Owner Royalty *not used*	0.00%	of revenues		
Site Owner Land Rent *used*	$333.33	thous/year		
escalating at	2.50%	/year	equiv to 0.113 c/kWh	
Property Tax	1.000%	of depreciable base		
escalating at	0.00%	/year		
where base depreciates	0.00%	/year, till hits	0.0%	
Insurance	1.025%	of depreciable base, esc. at	2.50%	/year
Major Maintenance & Overhauls	$500.00	thous/year or	$7,500	/turbine - year
escalating at	2.50%	/year	equiv to 0.169 c/kWh	
			--	
Inflation	2.50%	/year		
Interest Earned on Reserves	3.00%	/year; Interest on Work. Cap	0.50%	/year

Capital Cost per kW installed capacity		1,332	[133200 / 100]
Cost per Annual kWh		$0.45	[133200 / 296088]
	--		
	--		
	--		

RETURNS

	using a discount rate of	10.00%		
1	Pre-tax Unleveraged IRR	3.922%	over 20 years	
	Net Present Value	(48,351)	using 10%	
	Payback	15	years	
2	After-tax Leveraged IRR	13.037%	over 20 years	Target 13%
	Net Present Value	10,340	using 10%	
	Payback	5	years	
2a	Cash-on-Cash Return, excluding PTC	6.884%	average	
	(before-tax cash on equity, non-discounted)	4.310%	minimum	

COST OF UTILITY ENERGY	+---- -->	$0.0466	/kWh - first year
in currency of 2005	+---- -->	$0.0537	/kWh - nominal levelized
	+---- -->	$0.0438	/kWh - constant$ levelized
in currency of the year	+---- -->	$0.0500	/kWh - year 21
in currency of 2004	+---- -->	$0.0524	/kWh - nominal levelized
	+---- -->	$0.0427	/kWh - constant$ levelized
using a discount rate of		8.50%	nominal
		5.85%	constant (with no inflation)

DEBT COVERAGE	--			Min Target
Senior Debt Coverage ratio:		2.188	average	-n/a-
		1.835	minimum	1.30 times
Secondary Debt Coverage ratio:		--	average	
--		--	minimum	

Equipment Overhaul Reserve & Drawdown?	no, not undertaken	ok
Every 10 years, at 0 %, 0%, 0% and 0% of plant cost.		

01/21/2005 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial incl'g Revenues; pg 5 (Cash Flow): COE disc rate; pg 7 (Debt): PTC details;
pg 9 (Work Sheet #1): depreciation; pg 11 (Work Sheet #2): senior debt; pg 13 (Work Sheet #3): secondary debt.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100 MW, using Class 4 Winds winds with a 33.8% capacity factor. Contract term is 20 years.
Capital Cost is $1272 /kW. O&M is $20.67 /kW and $0 /kWh and $500 thousand per year.

This Project TAKES the 10-year Section 45 Production Tax Credit.
Financing is 35% senior debt at 6.5% for 18 years and 0% secondary debt and 65% equity.
Sales Tax is $ 0 thousands. Property tax is 1 % of depreciable base, escalating at inflation, but with base depreciating at 0% per year till hits 0%.

Appendix G (cont.)

Sources and Uses of Funds **100 MW GenCo - 33.8 cf, Class 4, w/ PTC** **09/14/06** **4:56 PM**

Uses of Funds *in thousands of mixed-year dollars*

	Rotor Assembly		16,502		
	Drive Train & Nacelle		37,518		
	Controls, Safety System		667		
	Tower		6,733		
	Market Adjustment		20,000		
	Foundations, Transport, Roads		11,896		
	Assembly, Interconnect, Permits, Engr		13,998		
	Permit/Environmental Adjustment		1,886		
	Manufacturing Uncertainty		10,800		
6,000	Construction Contingency		6,000		
	Home Office Overhead		1,200		--
	Total	1,272 /kW		127,200	*
	Sales Tax	0		0	*
	Construction Financing	6,000		6,000	*
	(estimated as $120 mil * 10% * 12 mos * 50% for level draw)				
	Construction Insur.			0	*
	Land			0	
	Initial Working Capital: First Year			0	
	Debt Financing Fees	932		0	--
	(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)				
	Equity Financing Fees	2,597		0	--
	(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)				--
	Debt Service Reserve Fund	2,234		0	--
	Working Capital, Operating Reserve	517		0	
	Equipment Repair Reserve Initial Pmt			0	

				133,200	

Misc.

Start Year	2005
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%

Depreciation Rate #2 5%, 9.5%, 8.55%, 7.7%, 6.93%, 6.23%, 5.9%
5.9%, 5.91%, 5.9%, 5.91%, 5.9%, 5.91%, 5.9%
5.91%, 2.95%, 0%, 0%, 0%, 0%, 0%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

35.00%	Debt	46,620	at 6.500%	for 18 years	level mortgage
0.00%	Second Loan	0	at 7.500%	for 18 years	level mortgage
65.00%	Equity	86,580			
----------		----------		--	
100.00%		133,200		--	
				--	

Taxes

Marginal Tax Rate:	Federal	35.00%	corporate federal rate is 35%,
	State	7.69%	corporate "average" state is 7.69%,
	Combined	40.00%	
Investment Tax Credit		0.00%	

Depreciation *Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.*

Depreciation Class Life #1	5	years; Percent at Life #1		100.00%	ok
Depreciation Class Life #2	15	years; Percent at Life #2		0.00%	ok
Amortization for Equity Finc'g Fees	40.00%		40.00%	20.00%	(See B207 on Sheet2.)

Tax Treatment

Sum of Depreciable Items		133,200	including sales tax		
Primary System Depreciable Base			133,200	5	years
less Tax Credit Adjustmt	50.00%	0			
Primary System Depreciable Base		133,200			
Other Depreciable Base			0	15	years
Amortization over Sr Debt's Life			0	18	years
Amortization over Second Debt's Life			0	18	years
5 years' Amortization			0		
1 years' Amortization			0		
No Write-Off			0		
Land			0		
First Year Start-Up (expensed in yr 1)			0		
Reserve Funds			0		

			133,200	ok	

Revenues

Energy Pmt	$0.0466	/kWh at	2.00%	/year beginning in year	1
Energy Pmt	$0.0500	/kWh at	2.00%	/year beginning in year	21
Capacity Pmt	$0.00	/kWh at	1.00%	/year	

Earnings | **100 MW GenCo - 33.8 cf, Class 4, w/ PTC** | **09/14/06** | **4:56 PM**

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Revenues											
	Energy Payment		13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490
	Capacity Payment		0	0	0	0	0	0	0	0	0	0
	Interest on Reserves		0	0	0	0	0	0	0	0	0	0
	Total Revenues		13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490
	Operating Costs											
	Operations & Maintenance - fixed		2,067	2,119	2,172	2,226	2,282	2,339	2,397	2,457	2,518	2,581
	Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent		333	342	350	359	368	377	387	396	406	416
	Property Tax		1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332
	Insurance		1,365	1,399	1,434	1,470	1,507	1,545	1,583	1,623	1,663	1,705
	Major Maintenance & Overhauls		500	513	525	538	552	566	580	594	609	624
	Total Operating Costs		5,598	5,704	5,814	5,926	6,040	6,158	6,279	6,402	6,529	6,659
	Operating Income		8,200	8,369	8,542	8,717	8,895	9,076	9,260	9,447	9,637	9,830
	Other Expenses											
	Interest on Loan #1		3,030	2,937	2,837	2,731	2,618	2,498	2,370	2,233	2,088	1,933
	Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
	Depreciation		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
	Repair Depreciation		0	0	0	0	0	0	0	0	0	0
	Amortization		0	0	0	0	0	0	0	0	0	0
	Total Other Expenses		29,670	45,561	28,412	18,076	17,963	10,170	2,370	2,233	2,088	1,933
	Before-Tax Profits		(21,470)	(37,191)	(19,870)	(9,359)	(9,068)	(1,095)	6,890	7,213	7,549	7,897
40.00%	Income Tax Paid (Benefit Rec'd)		(8,588)	(14,877)	(7,948)	(3,744)	(3,627)	(438)	2,756	2,885	3,020	3,159
	Investment Tax Credit Received		0	0								
	Production Tax Credits Received		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
	After-Tax Profits		(7,256)	(16,549)	(6,012)	443	769	5,708	10,658	11,015	11,384	11,764

Earnings — **100 MW GenCo - 33.8 cf, Class 4, w/ PTC** — **09/14/06** — **4:56 PM**

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Revenues											
	Energy Payment	16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0
	Capacity Payment	0	0	0	0	0	0	0	0	0	0	0
	Interest on Reserves	0	0	0	0	0	0	0	0	0	0	0
	Total Revenues	16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0
	Operating Costs											
	Operations & Maintenance - fixed	2,646	2,712	2,780	2,849	2,921	2,994	3,068	3,145	3,224	3,304	0
	Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent	427	437	448	460	471	483	495	507	520	533	0
	Property Tax	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	0
	Insurance	1,748	1,791	1,836	1,882	1,929	1,977	2,027	2,077	2,129	2,183	0
	Major Maintenance & Overhauls	640	656	672	689	706	724	742	761	780	799	0
	Total Operating Costs	6,792	6,929	7,069	7,212	7,359	7,510	7,664	7,823	7,985	8,151	0
	Operating Income	10,027	10,227	10,430	10,637	10,847	11,060	11,277	11,497	11,722	11,949	0
	Other Expenses											
	Interest on Loan #1	1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
	Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
	Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Amortization	0	0	0	0	0	0	0	0	0	0	0
	Total Other Expenses	1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
	Before-Tax Profits	8,258	8,634	9,024	9,429	9,851	10,291	10,748	11,225	11,722	11,949	0
40.00%	Income Tax Paid (Benefit Rec'd)	3,303	3,453	3,610	3,772	3,941	4,116	4,299	4,490	4,689	4,780	0
	Investment Tax Credit Received											
	Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits	4,955	5,180	5,414	5,658	5,911	6,174	6,449	6,735	7,033	7,170	0

Cash Flow & COE

100 MW GenCo - 33.8 cf, Class 4, w/ PTC 09/14/06 4:56 PM

All figures in $thousands.	0	1	2	3	4	5	6	7	8	9	10
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Before-Tax Profits		(21,470)	(37,191)	(19,870)	(9,359)	(9,068)	(1,095)	6,890	7,213	7,549	7,897
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
Amortization		0	0	0	0	0	0	0	0	0	0
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
Subtract Off:											
Loan #1 Principal		1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Before-Tax Cash		3,731	3,901	4,073	4,248	4,426	4,607	4,791	4,978	5,168	5,362
Taxes Payable (Benefit Received)		(8,588)	(14,877)	(7,948)	(3,744)	(3,627)	(438)	2,756	2,885	3,020	3,159
Investment Tax Credit		0	0								
Production Tax Credit		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
After-Tax Cash	(86,580)	17,945	24,544	17,931	14,050	14,263	11,410	8,559	8,780	9,003	9,229

After-tax IRR 13.037%
using starting estimate of 12.000% .
Net Present Value 10,340 , using 10.00% as discount rate for developer
Payback 5

1	1	1	1	1	0	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value of money [and discount factor] and excluding tax credits, tax losses, tax payments) Minimum 4.31% <-- -- Reset both as years of project
Average 6.88%

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Before-Tax Cash and Equity Investmen	(86,580)	3,731	3,901	4,073	4,248	4,426	4,607	4,791	4,978	5,168	5,362
BT Cash to Equity Investment (not discounted)		4.31%	4.51%	4.70%	4.91%	5.11%	5.32%	5.53%	5.75%	5.97%	6.19%

		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490
	Capacity	0	0	0	0	0	0	0	0	0	0
Total (thousands)		13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490

Net Present Value 150,570 , using 8.500% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 15,911 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 5.50% for tax-free coop; 8.5% for IOU) *

lev COE/kWh $0.0537 in nominal terms of 2005
lev COE/kWh $0.0524 in nominal terms of 2004

04/30/01 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

1st-yr Cost $0.0466
Constant $ NPV 150,570 , as nominal
Constant $ levelized 12,972 , using 5.854% = (1 + 0.085)/(1 + 0.025) - 1
lev COE/kWh $0.0438 in constant terms of 2005
lev COE/kWh $0.0427 in constant terms of 2004

Cash Flow & COE

100 MW GenCo - 33.8 cf, Class 4, w/ PTC 09/14/06 4:56 PM

All figures in $thousands.	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020	17 2021	18 2022	19 2023	20 2024	21 2025
Before-Tax Profits	8,258	8,634	9,024	9,429	9,851	10,291	10,748	11,225	11,722	11,949	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0
Released from Reserve	0	0	0	0	0	0	0	0	0	0	0
Total Additions	0	0	0	0	0	0	0	0	0	0	0
Subtract Off:											
Loan #1 Principal	2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Before-Tax Cash	5,558	5,758	5,961	6,168	6,378	6,591	6,808	7,029	11,722	11,949	0
Taxes Payable (Benefit Received)	3,303	3,453	3,610	3,772	3,941	4,116	4,299	4,490	4,689	4,780	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	2,255	2,305	2,352	2,396	2,437	2,475	2,509	2,539	7,033	7,170	0
	0	0	0	0	0	0	0	0	0	0	0
:t life varies.											
Before-Tax Cash and Equity Investmen	5,558	5,758	5,961	6,168	6,378	6,591	6,808	7,029	11,722	11,949	0
BT Cash to Equity Investment (not discc	6.42%	6.65%	6.89%	7.12%	7.37%	7.61%	7.86%	8.12%	13.54%	13.80%	0.00%

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%
Electric Revenues:	Energy	16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)		16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0

*To figure Discount rate:

Utility debt	50.00%	6.50%
preferred	5.00%	6.30%
common	45.00%	11.00%
		8.52% weighted average cost of capital

Debt Redemption & PTC — **100 MW GenCo - 33.8 cf, Class 4, w/ PTC** — **09/14/06** **4:56 PM**

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Loan #1		46,620	at 6.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			46,620	45,182	43,650	42,018	40,281	38,430	36,459	34,360	32,125	29,744
Interest			3,030	2,937	2,837	2,731	2,618	2,498	2,370	2,233	2,088	1,933
Loan Guarantee Fees			0	0	0	0	0	0	0	0	0	0
Principal			1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Total			4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469
Available Cash: Operating Income			8,200	8,369	8,542	8,717	8,895	9,076	9,260	9,447	9,637	9,830
PTC monetization, if any			0	0	0	0	0	0	0	0	0	0
Total Debt Service			4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469
Debt Coverage Ratio			1.835	1.873	1.911	1.951	1.990	2.031	2.072	2.114	2.157	2.200
Average Ratio	2.188		not counting last partial year									
Minimum Ratio	1.835											
Loan #2		0	at 7.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			0	0	0	0	0	0	0	0	0	0
Interest			0	0	0	0	0	0	0	0	0	0
Principal			0	0	0	0	0	0	0	0	0	0
Total			0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?	yes		, where yes means pay senior debt first or no is pay both loans together.									
Available Cash: Op Income & PTC, if monetized			3,731	3,901	4,073	4,248	4,426	4,607	4,791	4,978	5,168	5,362
Total Debt Service			0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	1		Select 1 = escalating rate by formula or 2 = customized rate or 3 = TURNED OFF for no credit at all.							PTC expires 12/31/2007, unless extended.		
	ok											
1 Escalating Rate		{	Starting Credit	$0.019 /kWh;	Start Year		1		yr 1 fraction	1.000 }		
(enter data on right;		{	Escal Rate	2.500% year;	Last Year		10			}		
(calc'd rate in line 158;		{								}		
(selected rate in line 163.)		{	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687 }	6,854	7,026
2 Customized Absolute			0	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854
	$/kWh		0.01900	0.01948	0.01996	0.02046	0.02097	0.02150	0.02203	0.02259	0.02315	0.02373
Active Credit:	$thous		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026

Debt Redemption & PTC 100 MW GenCo - 33.8 cf, Class 4, w/ PTC 09/14/06 4:56 PM

All figures in $thousands.

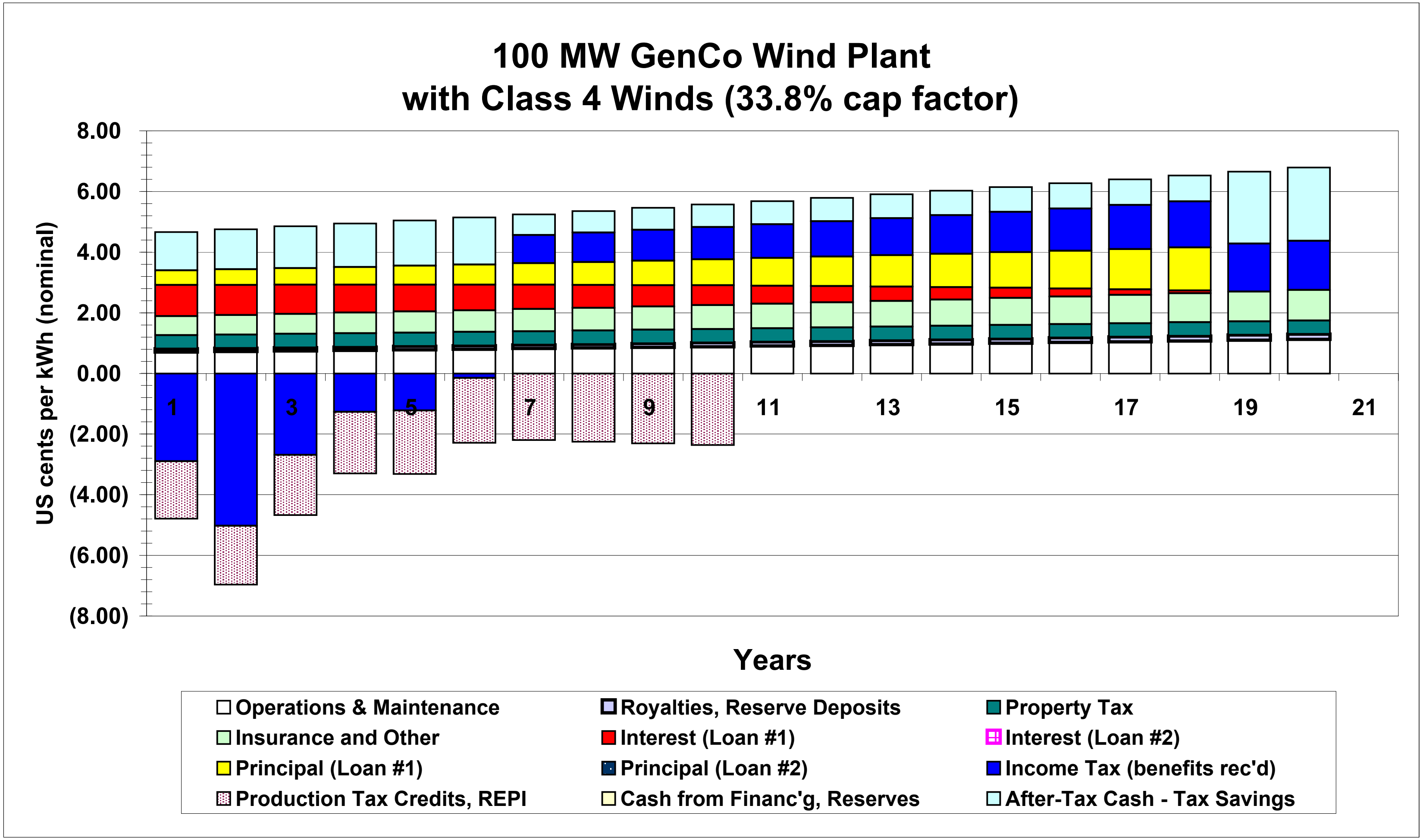
		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Loan #1												
Beginning Balance		27,209	24,509	21,633	18,571	15,309	11,835	8,136	4,196	0	0	0
Interest		1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
Principal		2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Total		4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	0	0	0
Available Cash: Operating Income		10,027	10,227	10,430	10,637	10,847	11,060	11,277	11,497	11,722	11,949	0
PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	0	0	0
Debt Coverage Ratio		2.244	2.289	2.334	2.380	2.427	2.475	2.524	2.573	0.000	0.000	0.000
Average Ratio	2.188											
Minimum Ratio	1.835											
Loan #2												
Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?												
Available Cash: Op Income & PTC, if m(		5,558	5,758	5,961	6,168	6,378	6,591	6,808	7,029	11,722	11,949	0
Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											

Prod'n Tax Credit	1											
	ok											
1 Escalating Rate (enter data on right; (calc'd rate in line 158; (selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2 Customized Absolute		7,026	0	0	0	0	0	0	0	0	0	0
	$/kWh											
Active Credit:	$thous	0	0	0	0	0	0	0	0	0	0	0

Graph Points 100 MW GenCo - 33.8 cf, Class 4, w/ PTC 09/14/06 4:56 PM

		1	2	3	4	5	6	7	8	9	10
	296,088,000 kWh/year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Cost Components in nominal US cents/kWh (money of the year)										
	Revenues	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569
1	Operations & Maintenance	0.698	0.716	0.733	0.752	0.771	0.790	0.810	0.830	0.851	0.872
2	Royalties, Reserve Deposits	0.113	0.115	0.118	0.121	0.124	0.127	0.131	0.134	0.137	0.141
3	Property Tax	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450
4	Insurance and Other	0.630	0.646	0.662	0.678	0.695	0.713	0.731	0.749	0.768	0.787
5	Interest (Loan #1)	1.023	0.992	0.958	0.922	0.884	0.844	0.800	0.754	0.705	0.653
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.486	0.517	0.551	0.587	0.625	0.666	0.709	0.755	0.804	0.856
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	(2.901)	(5.024)	(2.684)	(1.264)	(1.225)	(0.148)	0.931	0.974	1.020	1.067
10	Production Tax Credits, REPI	(1.900)	(1.948)	(1.996)	(2.046)	(2.097)	(2.150)	(2.203)	(2.259)	(2.315)	(2.373)
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	1.260	1.317	1.376	1.435	1.495	1.556	0.687	0.707	0.726	0.744
	Energy Revenues (with neg tax added as positive)	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569
check	Energy Revenues	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569
	Interest on Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569

Graph Points		100 MW GenCo - 33.8 cf, Class 4, w/ PTC								09/14/06	4:56 PM
		11	12	13	14	15	16	17	18	19	20	21
296,088,000	kWh/year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cost Components in nominal US cents/kWh (money of the												
Revenues		5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000
1	Operations & Maintenance	0.894	0.916	0.939	0.962	0.986	1.011	1.036	1.062	1.089	1.116	0.000
2	Royalties, Reserve Deposits	0.144	0.148	0.151	0.155	0.159	0.163	0.167	0.171	0.176	0.180	0.000
3	Property Tax	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.000
4	Insurance and Other	0.806	0.827	0.847	0.868	0.890	0.912	0.935	0.959	0.983	1.007	0.000
5	Interest (Loan #1)	0.597	0.538	0.475	0.408	0.336	0.260	0.179	0.092	0.000	0.000	0.000
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.912	0.971	1.034	1.102	1.173	1.249	1.331	1.417	0.000	0.000	0.000
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	1.116	1.166	1.219	1.274	1.331	1.390	1.452	1.516	1.584	1.614	0.000
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	0.762	0.778	0.794	0.809	0.823	0.836	0.847	0.857	2.375	2.421	0.000
	Energy Revenues (with neg tax added as positive)	5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000
check	Energy Revenues	5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000
	Interest on Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000


100 MW GenCo Wind Plant
with Class 4 Winds (33.8% cap factor)
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
US cents per kWh (nominal)
1
3
5
7
9
11
13
15
17
19
21
Years
Operations & Maintenance
Royalties, Reserve Deposits
Property Tax
Insurance and Other
Interest (Loan #1)
Interest (Loan #2)
Principal (Loan #1)
Principal (Loan #2)
Income Tax (benefits rec'd)
Production Tax Credits, REPI
Cash from Financ'g, Reserves
After-Tax Cash - Tax Savings

SUMMARY PAGE 100 MW GenCo - 33.8 cf, Class 4, monetized PTC 09/14/06 5:20 PM

File: 0914GenCoWind2004_MonetizedPTC.xls

Construction and Development Assumptions and Operating Results
All figures are in thousands of U.S. dollars.

Capital					Capital Cost per kW installed capacity		1,332	[133200 / 100]
Total Project Cost	133,200				Cost per Annual kWh		$0.45	[133200 / 296088]
Start Date	2005	at 100% for year 1						
Project Description	100 MW Wind Farm, using Class 4 Winds owned by taxable Generating Company using Balance Sheet Finance					-- -- --		
Finance					**RETURNS**			
Debt	46,620	at 6.500%	for 18 years		using a discount rate of		10.00%	
Secondary Debt	0	at 7.500%	for 18 years					
Equity	86,580			1	Pre-tax Unleveraged IRR		3.922%	over 20 years
	----------				Net Present Value		(48,351)	using 10%
Total	133,200				Payback		15	years
				2	After-tax Leveraged IRR		13.037%	over 20 years Target 13%
Operations					Net Present Value		10,340	using 10%
Net Rated Capacity	100,000	kW, using	1,500 kW-rated turbines		Payback		5	years
Actual Hours/Year	8,760	hours/year	67 turbines					
				2a	Cash-on-Cash Return, excluding PTC		6.884%	average
Wind Resource	Class 4 Winds				(before-tax cash on equity, non-discounted)		4.310%	minimum
Net Capacity Factor	33.80%							
Plant Annual Electricity	296,088	thou kWh/year			**COST OF UTILITY ENERGY**	+---- -->	$0.0466	/kWh - first year
Contract Term	20	years			in currency of 2005	+---- -->	$0.0537	/kWh - nominal levelized
						+---- -->	$0.0438	/kWh - constant$ levelized
Operations & Maintenance - fixed	20.67	/kW or	$31,005 /turbine - year		in currency of the year	+---- -->	$0.0500	/kWh - year 21
escalating at	2.50%	/year	equiv to 0.698 c/kWh		in currency of 2004	+---- -->	$0.0524	/kWh - nominal levelized
Operations & Maintenance - var.	$0.000	/kWh				+---- -->	$0.0427	/kWh - constant$ levelized
escalating at	2.50%	/year						
For land payment, select 1 = percentage revenues, 2 = fixed rent			2 ok		using a discount rate of	8.50%	nominal	
Site Owner Royalty *not used*	0.00%	of revenues				5.85%	constant (with no inflation)	
Site Owner Land Rent *used*	$333.33	thous/year						
escalating at	2.50%	/year	equiv to 0.113 c/kWh					
Property Tax	1.000%	of depreciable base			**DEBT COVERAGE**	*** PTC is monetized to cover debt paymer		Min Target
escalating at	0.00%	/year			Senior Debt Coverage ratio:		2.971 average	-n/a-
where base depreciates	0.00%	/year, till hits	0.0%				2.244 minimum	1.30 times
Insurance	1.025%	of depreciable base, esc. at	2.50% /year		Secondary Debt Coverage ratio:		-- average	
Major Maintenance & Overhauls	$500.00	thous/year or	$7,500 /turbine - year		--		-- minimum	
escalating at	2.50%	/year	equiv to 0.169 c/kWh --					
Inflation	2.50%	/year			Equipment Overhaul Reserve & Drawdown?	no, not undertaken		ok
Interest Earned on Reserves	3.00%	/year; Interest on Work. Cap	0.50% /year		Every 10 years, at 0 %, 0%, 0% and 0% of plant cost.			

01/21/2005 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial incl'g Revenues; pg 5 (Cash Flow): COE disc rate; pg 7 (Debt): PTC details;
pg 9 (Work Sheet #1): depreciation; pg 11 (Work Sheet #2): senior debt; pg 13 (Work Sheet #3): secondary debt.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100 MW, using Class 4 Winds winds with a 33.8% capacity factor. Contract term is 20 years.
Capital Cost is $1272 /kW. O&M is $20.67 /kW and $0 /kWh and $500 thousand per year.

This Project TAKES the 10-year Section 45 Production Tax Credit.
Financing is 35% senior debt at 6.5% for 18 years and 0% secondary debt and 65% equity.
Sales Tax is $ 0 thousands. Property tax is 1 % of depreciable base, escalating at inflation, but with base depreciating at 0% per year till hits 0%.

Sources and Uses of Funds

100 MW GenCo - 33.8 cf, Class 4, monetized PTC **09/14/06** **5:20 PM**

Uses of Funds *in thousands of mixed-year dollars*

	Rotor Assembly			16,502		
	Drive Train & Nacelle			37,518		
	Controls, Safety System			667		
	Tower			6,733		
	Market Adjustment			20,000		
	Foundations, Transport, Roads			11,896		
	Assembly, Interconnect, Permits, Engr			13,998		
	Permit/Environmental Adjustment			1,886		
	Manufacturing Uncertainty			10,800		
6,000	Construction Contingency			6,000		
	Home Office Overhead			1,200		--
	Total	1,272	/kW		127,200	*
	Sales Tax	0			0	*
	Construction Financing	6,000			6,000	*
	(estimated as $120 mil * 10% * 12 mos * 50% for level draw)					
	Construction Insur.				0	*
	Land				0	
	Initial Working Capital: First Year				0	
	Debt Financing Fees	932			0	--
	(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)					
	Equity Financing Fees	2,597			0	--
	(Tax Advice, Equity Organizational Costs, etc.;					--
	part amortized in 1 year, part in 5 years, part excluded)					
	Debt Service Reserve Fund	2,234			0	--
	Working Capital, Operating Reserve	517			0	
	Equipment Repair Reserve Initial Pmt				0	

					133,200	

Misc.

Start Year	2005
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%

Depreciation Rate #2 5%, 9.5%, 8.55%, 7.7%, 6.93%, 6.23%, 5.9%
5.9%, 5.91%, 5.9%, 5.91%, 5.9%, 5.91%, 5.9%
5.91%, 2.95%, 0%, 0%, 0%, 0%, 0%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

35.00%	Debt	46,620	at 6.500%	for 18 years	level mortgage
0.00%	Second Loan	0	at 7.500%	for 18 years	level mortgage
65.00%	Equity	86,580			
----------		----------		--	
100.00%		133,200		--	
				--	

Taxes

Marginal Tax Rate:	Federal	35.00%	corporate federal rate is 35%,
	State	7.69%	corporate "average" state is 7.69%,
	Combined	40.00%	
Investment Tax Credit		0.00%	

Depreciation *Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.*

Depreciation Class Life #1	5	years; Percent at Life #1		100.00%	ok
Depreciation Class Life #2	15	years; Percent at Life #2		0.00%	ok
Amortization for Equity Finc'g Fees	40.00%		40.00%	20.00%	(See B207 on Sheet2.)

Tax Treatment

Sum of Depreciable Items		133,200	including sales tax		
Primary System Depreciable Base			133,200	5	years
less Tax Credit Adjustmt	50.00%	0			
Primary System Depreciable Base		133,200			
Other Depreciable Base			0	15	years
Amortization over Sr Debt's Life			0	18	years
Amortization over Second Debt's Life			0	18	years
5 years' Amortization			0		
1 years' Amortization			0		
No Write-Off			0		
Land			0		
First Year Start-Up (expensed in yr 1)			0		
Reserve Funds			0		

			133,200	ok	

Revenues

Energy Pmt	$0.0466	/kWh at	2.00%	/year beginning in year	1
Energy Pmt	$0.0500	/kWh at	2.00%	/year beginning in year	21
Capacity Pmt	$0.00	/kWh at	1.00%	/year	

Earnings — **100 MW GenCo - 33.8 cf, Class 4, monetized PTC** — **09/14/06** **5:20 PM**

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Revenues											
	Energy Payment		13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490
	Capacity Payment		0	0	0	0	0	0	0	0	0	0
	Interest on Reserves		0	0	0	0	0	0	0	0	0	0
	Total Revenues		13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490
	Operating Costs											
	Operations & Maintenance - fixed		2,067	2,119	2,172	2,226	2,282	2,339	2,397	2,457	2,518	2,581
	Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent		333	342	350	359	368	377	387	396	406	416
	Property Tax		1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332
	Insurance		1,365	1,399	1,434	1,470	1,507	1,545	1,583	1,623	1,663	1,705
	Major Maintenance & Overhauls		500	513	525	538	552	566	580	594	609	624
	Total Operating Costs		5,598	5,704	5,814	5,926	6,040	6,158	6,279	6,402	6,529	6,659
	Operating Income		8,200	8,369	8,542	8,717	8,895	9,076	9,260	9,447	9,637	9,830
	Other Expenses											
	Interest on Loan #1		3,030	2,937	2,837	2,731	2,618	2,498	2,370	2,233	2,088	1,933
	Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
	Depreciation		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
	Repair Depreciation		0	0	0	0	0	0	0	0	0	0
	Amortization		0	0	0	0	0	0	0	0	0	0
	Total Other Expenses		29,670	45,561	28,412	18,076	17,963	10,170	2,370	2,233	2,088	1,933
	Before-Tax Profits		(21,470)	(37,191)	(19,870)	(9,359)	(9,068)	(1,095)	6,890	7,213	7,549	7,897
40.00%	Income Tax Paid (Benefit Rec'd)		(8,588)	(14,877)	(7,948)	(3,744)	(3,627)	(438)	2,756	2,885	3,020	3,159
	Investment Tax Credit Received		0	0								
	Production Tax Credits Received		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
	After-Tax Profits		(7,256)	(16,549)	(6,012)	443	769	5,708	10,658	11,015	11,384	11,764

Earnings **100 MW GenCo - 33.8 cf, Class 4, monetized PTC** **09/14/06** **5:20 PM**

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Revenues											
	Energy Payment	16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0
	Capacity Payment	0	0	0	0	0	0	0	0	0	0	0
	Interest on Reserves	0	0	0	0	0	0	0	0	0	0	0
	Total Revenues	16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0
	Operating Costs											
	Operations & Maintenance - fixed	2,646	2,712	2,780	2,849	2,921	2,994	3,068	3,145	3,224	3,304	0
	Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent	427	437	448	460	471	483	495	507	520	533	0
	Property Tax	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	1,332	0
	Insurance	1,748	1,791	1,836	1,882	1,929	1,977	2,027	2,077	2,129	2,183	0
	Major Maintenance & Overhauls	640	656	672	689	706	724	742	761	780	799	0
	Total Operating Costs	6,792	6,929	7,069	7,212	7,359	7,510	7,664	7,823	7,985	8,151	0
	Operating Income	10,027	10,227	10,430	10,637	10,847	11,060	11,277	11,497	11,722	11,949	0
	Other Expenses											
	Interest on Loan #1	1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
	Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
	Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Amortization	0	0	0	0	0	0	0	0	0	0	0
	Total Other Expenses	1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
	Before-Tax Profits	8,258	8,634	9,024	9,429	9,851	10,291	10,748	11,225	11,722	11,949	0
40.00%	Income Tax Paid (Benefit Rec'd)	3,303	3,453	3,610	3,772	3,941	4,116	4,299	4,490	4,689	4,780	0
	Investment Tax Credit Received											
	Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits	4,955	5,180	5,414	5,658	5,911	6,174	6,449	6,735	7,033	7,170	0

Cash Flow & COE

100 MW GenCo - 33.8 cf, Class 4, monetized PTC — 09/14/06 5:20 PM

All figures in $thousands.	0 2004	1 2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012	9 2013	10 2014
Before-Tax Profits		(21,470)	(37,191)	(19,870)	(9,359)	(9,068)	(1,095)	6,890	7,213	7,549	7,897
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
Amortization		0	0	0	0	0	0	0	0	0	0
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		26,640	42,624	25,574	15,345	15,345	7,672	0	0	0	0
Subtract Off:											
Loan #1 Principal		1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Before-Tax Cash		3,731	3,901	4,073	4,248	4,426	4,607	4,791	4,978	5,168	5,362
Taxes Payable (Benefit Received)		(8,588)	(14,877)	(7,948)	(3,744)	(3,627)	(438)	2,756	2,885	3,020	3,159
Investment Tax Credit		0	0								
Production Tax Credit		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
After-Tax Cash	(86,580)	17,945	24,544	17,931	14,050	14,263	11,410	8,559	8,780	9,003	9,229

After-tax IRR 13.037%
using starting estimate of 12.000% .
Net Present Value 10,340 , using 10.00% as discount rate for developer
Payback 5

	1	1	1	1	1	0	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value of money [and discount factor] and excluding tax credits, tax losses, tax payments)
Minimum 4.31% <-- -- Reset both as years of project
Average 6.88%

	0	1	2	3	4	5	6	7	8	9	10
Before-Tax Cash and Equity Investmen	(86,580)	3,731	3,901	4,073	4,248	4,426	4,607	4,791	4,978	5,168	5,362
BT Cash to Equity Investment (not discounted)		4.31%	4.51%	4.70%	4.91%	5.11%	5.32%	5.53%	5.75%	5.97%	6.19%

		1	2	3	4	5	6	7	8	9	10
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490
	Capacity	0	0	0	0	0	0	0	0	0	0
Total (thousands)		13,798	14,074	14,355	14,642	14,935	15,234	15,538	15,849	16,166	16,490

Net Present Value 150,570 , using 8.500% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 15,911 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 5.50% for tax-free coop; 8.5% for IOU) *

lev COE/kWh $0.0537 in nominal terms of 2005
lev COE/kWh $0.0524 in nominal terms of 2004

04/30/01 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

1st-yr Cost $0.0466
Constant $ NPV 150,570 , as nominal
Constant $ levelized 12,972 , using 5.854% = (1 + 0.085)/(1 + 0.025) - 1
lev COE/kWh $0.0438 in constant terms of 2005
lev COE/kWh $0.0427 in constant terms of 2004

Cash Flow & COE 100 MW GenCo - 33.8 cf, Class 4, monetized PTC 09/14/06 5:20 PM

All figures in $thousands.	11	12	13	14	15	16	17	18	19	20	21
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Before-Tax Profits	8,258	8,634	9,024	9,429	9,851	10,291	10,748	11,225	11,722	11,949	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	0	0	0	0	0	0	0	0	0	0	0
Released from Reserve	0	0	0	0	0	0	0	0	0	0	0
Total Additions	0	0	0	0	0	0	0	0	0	0	0
Subtract Off:											
Loan #1 Principal	2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Before-Tax Cash	5,558	5,758	5,961	6,168	6,378	6,591	6,808	7,029	11,722	11,949	0
Taxes Payable (Benefit Received)	3,303	3,453	3,610	3,772	3,941	4,116	4,299	4,490	4,689	4,780	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	2,255	2,305	2,352	2,396	2,437	2,475	2,509	2,539	7,033	7,170	0
	0	0	0	0	0	0	0	0	0	0	0
:t life varies.											
Before-Tax Cash and Equity Investmen	5,558	5,758	5,961	6,168	6,378	6,591	6,808	7,029	11,722	11,949	0
BT Cash to Equity Investment (not disc	6.42%	6.65%	6.89%	7.12%	7.37%	7.61%	7.86%	8.12%	13.54%	13.80%	0.00%

		11	12	13	14	15	16	17	18	19	20	21
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%
Electric Revenues:	Energy	16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)		16,819	17,156	17,499	17,849	18,206	18,570	18,941	19,320	19,707	20,101	0

*To figure Discount rate:

Utility debt	50.00%	6.50%
preferred	5.00%	6.30%
common	45.00%	11.00%
		8.52% weighted average cost of capital

Debt Redemption & PTC — **100 MW GenCo - 33.8 cf, Class 4, monetized PTC** — **09/14/06** — **5:20 PM**

All figures in $thousands.

		0 2004	1 2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012	9 2013	10 2014
Loan #1		46,620	at 6.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			46,620	45,182	43,650	42,018	40,281	38,430	36,459	34,360	32,125	29,744
Interest			3,030	2,937	2,837	2,731	2,618	2,498	2,370	2,233	2,088	1,933
Loan Guarantee Fees			0	0	0	0	0	0	0	0	0	0
Principal			1,438	1,532	1,632	1,738	1,851	1,971	2,099	2,235	2,381	2,535
Total			4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469
Available Cash: Operating Income			8,200	8,369	8,542	8,717	8,895	9,076	9,260	9,447	9,637	9,830
PTC monetization, if any			5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
Total Debt Service			4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469
Debt Coverage Ratio			3.094	3.163	3.234	3.306	3.380	3.455	3.532	3.610	3.690	3.772
Average Ratio	2.971		not counting last partial year									
Minimum Ratio	2.244											
Loan #2		0	at 7.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			0	0	0	0	0	0	0	0	0	0
Interest			0	0	0	0	0	0	0	0	0	0
Principal			0	0	0	0	0	0	0	0	0	0
Total			0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?	yes		, where yes means pay senior debt first or no is pay both loans together.									
Available Cash: Op Income & PTC, if monetized			9,357	9,667	9,983	10,306	10,636	10,972	11,315	11,665	12,023	12,387
Total Debt Service			0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											

Prod'n Tax Credit 1 — Select 1 = escalating rate by formula or 2 = customized rate or 3 = TURNED OFF for no credit at all. PTC expires 12/31/2007, unless extended.

ok

1 Escalating Rate { Starting Credit $0.019 /kWh; Start Year 1 yr 1 fraction 1.000 }

(enter data on right; { Escal Rate 2.500% year; Last Year 10 }

(calc'd rate in line 158; { }

		1	2	3	4	5	6	7	8	9	10
(selected rate in line 163.)	{	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
2 Customized Absolute		0	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854
	$/kWh	0.01900	0.01948	0.01996	0.02046	0.02097	0.02150	0.02203	0.02259	0.02315	0.02373
Active Credit:	$thous	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026

Debt Redemption & PTC 100 MW GenCo - 33.8 cf, Class 4, monetized PTC 09/14/06 5:20 PM

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Loan #1												
Beginning Balance		27,209	24,509	21,633	18,571	15,309	11,835	8,136	4,196	0	0	0
Interest		1,769	1,593	1,406	1,207	995	769	529	273	0	0	0
Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
Principal		2,700	2,876	3,063	3,262	3,474	3,699	3,940	4,196	0	0	0
Total		4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	0	0	0
Available Cash: Operating Income		10,027	10,227	10,430	10,637	10,847	11,060	11,277	11,497	11,722	11,949	0
PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	0	0	0
Debt Coverage Ratio		2.244	2.289	2.334	2.380	2.427	2.475	2.524	2.573	0.000	0.000	0.000
Average Ratio	2.971											
Minimum Ratio	2.244											
Loan #2												
Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?												
Available Cash: Op Income & PTC, if m		5,558	5,758	5,961	6,168	6,378	6,591	6,808	7,029	11,722	11,949	0
Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											

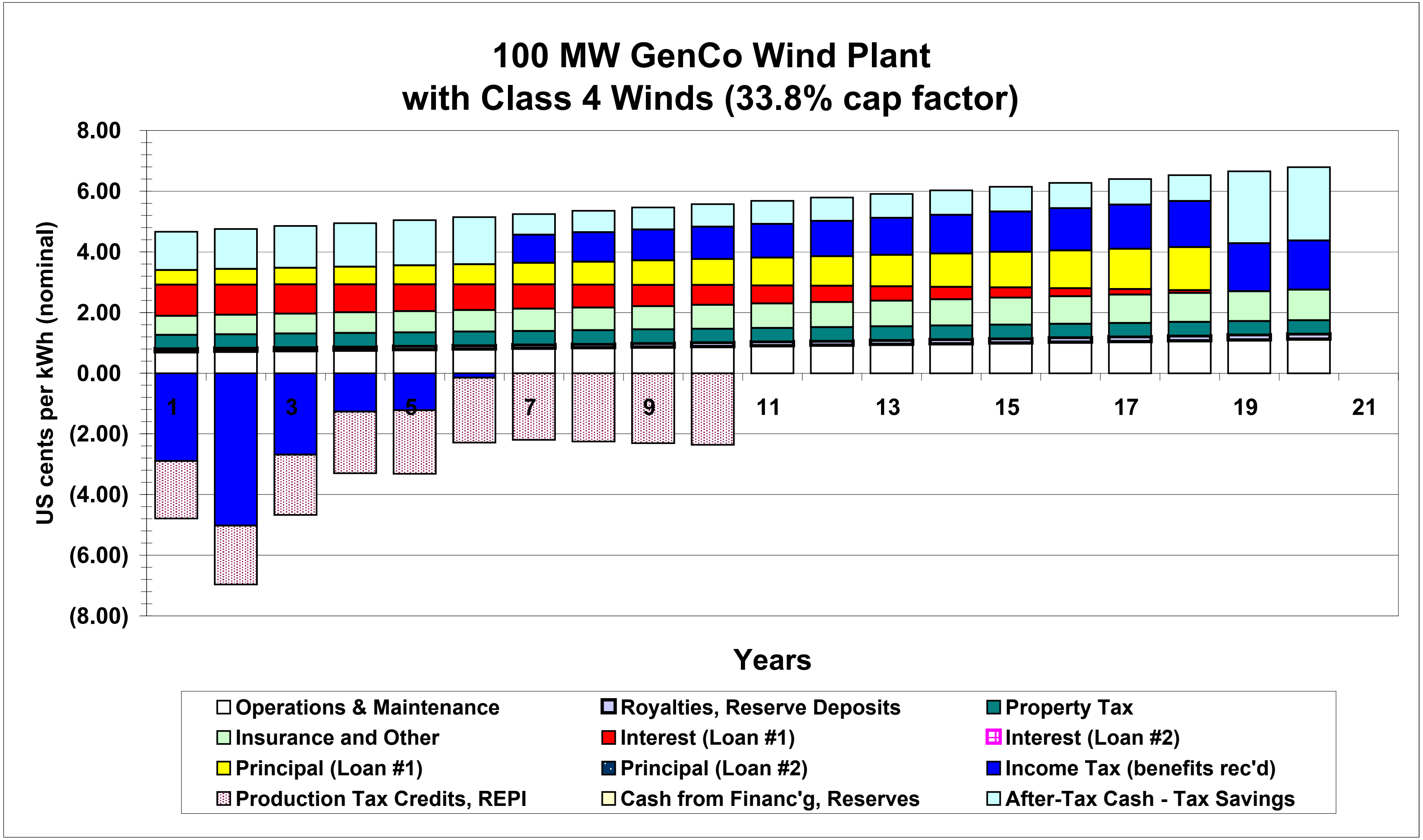
Prod'n Tax Credit	1											
	ok											
1 Escalating Rate (enter data on right; (calc'd rate in line 158; (selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2 Customized Absolute		7,026	0	0	0	0	0	0	0	0	0	0
	$/kWh											
Active Credit:	$thous	0	0	0	0	0	0	0	0	0	0	0

Graph Points — **100 MW GenCo - 33.8 cf, Class 4, monetized PTC** — **09/14/06** **5:20 PM**

		1	2	3	4	5	6	7	8	9	10
	296,088,000 kWh/year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Cost Components										
	in nominal US cents/kWh (money of the year)										
	Revenues	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569
1	Operations & Maintenance	0.698	0.716	0.733	0.752	0.771	0.790	0.810	0.830	0.851	0.872
2	Royalties, Reserve Deposits	0.113	0.115	0.118	0.121	0.124	0.127	0.131	0.134	0.137	0.141
3	Property Tax	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450
4	Insurance and Other	0.630	0.646	0.662	0.678	0.695	0.713	0.731	0.749	0.768	0.787
5	Interest (Loan #1)	1.023	0.992	0.958	0.922	0.884	0.844	0.800	0.754	0.705	0.653
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.486	0.517	0.551	0.587	0.625	0.666	0.709	0.755	0.804	0.856
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	(2.901)	(5.024)	(2.684)	(1.264)	(1.225)	(0.148)	0.931	0.974	1.020	1.067
10	Production Tax Credits, REPI	(1.900)	(1.948)	(1.996)	(2.046)	(2.097)	(2.150)	(2.203)	(2.259)	(2.315)	(2.373)
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	1.260	1.317	1.376	1.435	1.495	1.556	0.687	0.707	0.726	0.744
	Energy Revenues (with neg tax added as positive)	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569
check	Energy Revenues	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569
	Interest on Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	4.660	4.753	4.848	4.945	5.044	5.145	5.248	5.353	5.460	5.569

Graph Points — **100 MW GenCo - 33.8 cf, Class 4, monetized PTC** — **09/14/06** **5:20 PM**

		11	12	13	14	15	16	17	18	19	20	21
	296,088,000 kWh/year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Cost Components in nominal US cents/kWh (money of the											
	Revenues	5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000
1	Operations & Maintenance	0.894	0.916	0.939	0.962	0.986	1.011	1.036	1.062	1.089	1.116	0.000
2	Royalties, Reserve Deposits	0.144	0.148	0.151	0.155	0.159	0.163	0.167	0.171	0.176	0.180	0.000
3	Property Tax	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.450	0.000
4	Insurance and Other	0.806	0.827	0.847	0.868	0.890	0.912	0.935	0.959	0.983	1.007	0.000
5	Interest (Loan #1)	0.597	0.538	0.475	0.408	0.336	0.260	0.179	0.092	0.000	0.000	0.000
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	0.912	0.971	1.034	1.102	1.173	1.249	1.331	1.417	0.000	0.000	0.000
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	1.116	1.166	1.219	1.274	1.331	1.390	1.452	1.516	1.584	1.614	0.000
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	0.762	0.778	0.794	0.809	0.823	0.836	0.847	0.857	2.375	2.421	0.000
	Energy Revenues (with neg tax added as positive)	5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000
check	Energy Revenues	5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000
	Interest on Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	5.681	5.794	5.910	6.028	6.149	6.272	6.397	6.525	6.656	6.789	0.000


100 MW GenCo Wind Plant
with Class 4 Winds (33.8% cap factor)
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
US cents per kWh (nominal)
1
3
5
7
9
11
13
15
17
19
21
Years
Operations & Maintenance
Royalties, Reserve Deposits
Property Tax
Insurance and Other
Interest (Loan #1)
Interest (Loan #2)
Principal (Loan #1)
Principal (Loan #2)
Income Tax (benefits rec'd)
Production Tax Credits, REPI
Cash from Financ'g, Reserves
After-Tax Cash - Tax Savings

SUMMARY PAGE 100 MW IPP - 33.8 cf, Class 4, no PTC 09/14/06 6:17 PM

File: 0914IPPWind2004_noPTC.xls

Construction and Development Assumptions and Operating Results

All figures are in thousands of U.S. dollars.

Capital				
Total Project Cost	140,650			
Start Date	2005	at 100% for year 1		
Project Description	100 MW Wind Farm, using Class 4 Winds owned by taxable IPP using limited recourse Project Finance			
Finance				
Debt	98,455	at 7.000%	for 15 years	
Secondary Debt	0	at 7.500%	for 18 years	
Equity	42,195			

Total	140,650			
Operations				
Net Rated Capacity	100,000	kW, using	1,500	kW-rated turbines
Actual Hours/Year	8,760	hours/year	67	turbines
Wind Resource	Class 4 Winds			
Net Capacity Factor	33.80%			
Plant Annual Electricity	296,088	thou kWh/year		
Contract Term	20	years		
Operations & Maintenance - fixed	20.67	/kW or	$31,005	/turbine - year
escalating at	2.50%	/year	equiv to 0.698 c/kWh	
Operations & Maintenance - var.	$0.000	/kWh		
escalating at	2.50%	/year		
For land payment, select 1 = percentage revenues, 2 = fixed rent			2	ok
Site Owner Royalty *not used*	0.00%	of revenues		
Site Owner Land Rent *used*	$333.33	thous/year		
escalating at	2.50%	/year	equiv to 0.113 c/kWh	
Property Tax	1.000%	of depreciable base		
escalating at	0.00%	/year		
where base depreciates	0.00%	/year, till hits	0.0%	
Insurance	1.025%	of depreciable base, esc. at	2.50%	/year
Major Maintenance & Overhauls	$500.00	thous/year or	$7,500	/turbine - year
escalating at	2.50%	/year	equiv to 0.169 c/kWh	
			--	
Inflation	2.50%	/year		
Interest Earned on Reserves	3.00%	/year; Interest on Work. Cap	0.50%	/year

Capital Cost per kW installed capacity		1,407	[140650 / 100]	
Cost per Annual kWh		$0.48	[140650 / 296088]	
	--			
	--			
	--			
RETURNS				
using a discount rate of		10.00%		
1 Pre-tax Unleveraged IRR		12.316%	over 20 years	
Net Present Value		22,618	using 10%	
Payback		8	years	
2 After-tax Leveraged IRR		23.803%	over 20 years	Target 17%
Net Present Value		29,218	using 10%	
Payback		3	years	
2a Cash-on-Cash Return, excluding PTC		29.905%	average	
(before-tax cash on equity, non-discounted)		14.396%	minimum	
COST OF UTILITY ENERGY	+---- -->	$0.0753	/kWh - first year	
in currency of 2005	+---- -->	$0.0868	/kWh - nominal levelized	
	+---- -->	$0.0708	/kWh - constant$ levelized	
in currency of the year	+---- -->	$0.0500	/kWh - year 21	
in currency of 2004	+---- -->	$0.0847	/kWh - nominal levelized	
	+---- -->	$0.0691	/kWh - constant$ levelized	
using a discount rate of		8.50%	nominal	
		5.85%	constant (with no inflation)	
DEBT COVERAGE	--			Min Target
Senior Debt Coverage ratio:		1.800	average	1.80 times
		1.562	minimum	1.50 times
Secondary Debt Coverage ratio:		--	average	
--		--	minimum	
Equipment Overhaul Reserve & Drawdown?		no, not undertaken		ok
Every 10 years, at 0 %, 0%, and 0% of plant cost.				

01/21/2005 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial incl'g Revenues; pg 5 (Cash Flow): COE disc rate; pg 7 (Debt): PTC details;
pg 9 (Work Sheet #1): depreciation; pg 11 (Work Sheet #2): senior debt; pg 13 (Work Sheet #3): secondary debt.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100 MW, using Class 4 Winds winds with a 33.8% capacity factor. Contract term is 20 years.
Capital Cost is $1260 /kW. O&M is $20.67 /kW and $0 /kWh and $500 thousand per year.

This Project takes NO Production Tax Credit.
Financing is 70% senior debt at 7% for 15 years and 0% secondary debt and 30% equity.
Sales Tax is $ 0 thousands. Property tax is 1 % of depreciable base, escalating at inflation, but with base depreciating at 0% per year till hits 0%. |::

Sources and Uses of Funds

100 MW IPP - 33.8 cf, Class 4, no PTC 09/14/06 6:17 PM

Uses of Funds

in thousands of mixed-year dollars

	Rotor Assembly			16,502		
	Drive Train & Nacelle			37,518		
	Controls, Safety System			667		
	Tower			6,733		
	Market Adjustment			20,000		
	Foundations, Transport, Roads			11,896		
	Assembly, Interconnect, Permits, Engr			13,998		
	Permit/Environmental Adjustment			1,886		
	Manufacturing Uncertainty			10,800		
6,000	Construction Contingency			6,000		
	Home Office Overhead			0		--
	Total	1,260	/kW		126,000	*
	Sales Tax	0			0	*
	Construction Financing	6,000			6,000	*
	(estimated as $120 mil * 10% * 12 mos * 50% for level draw)					
	Construction Insur.				0	*
	Land				0	
	Initial Working Capital: First Year				0	
	Debt Financing Fees	1,969			1,970	--
	(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)					
	Equity Financing Fees	1,266			1,270	--
	(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)					--
	Debt Service Reserve Fund	5,405			5,410	--
	Working Capital, Operating Reserve	517			0	
	Equipment Repair Reserve Initial Pmt				0	

					140,650	

Misc.

Start Year	2005
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1: 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%

Depreciation Rate #2: 5%, 9.5%, 8.55%, 7.7%, 6.93%, 6.23%, 5.9%
5.9%, 5.91%, 5.9%, 5.91%, 5.9%, 5.91%, 5.9%
5.91%, 2.95%, 0%, 0%, 0%, 0%, 0%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

70.00%	Debt	98,455	at 7.000%	for 15 years	level mortgage
0.00%	Second Loan	0	at 7.500%	for 18 years	level mortgage
30.00%	Equity	42,195			
----------		----------		--	
100.00%		140,650		--	
				--	

Taxes

Marginal Tax Rate:	Federal	35.00%	corporate federal rate is 35%,
	State	7.69%	corporate "average" state is 7.69%,
	Combined	40.00%	
Investment Tax Credit		0.00%	

Depreciation

Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.

Depreciation Class Life #1	5	years; Percent at Life #1		100.00%	ok
Depreciation Class Life #2	15	years; Percent at Life #2		0.00%	ok
Amortization for Equity Finc'g Fees	40.00%		40.00%	20.00%	(See B207 on Sheet2.)

Tax Treatment

Sum of Depreciable Items		132,000	including sales tax		
Primary System Depreciable Base			132,000	5	years
less Tax Credit Adjustmt	50.00%	0			
Primary System Depreciable Base		132,000			
Other Depreciable Base			0	15	years
Amortization over Sr Debt's Life			1,970	15	years
Amortization over Second Debt's Life			0	18	years
5 years' Amortization			508		
1 years' Amortization			508		
No Write-Off			254		
Land			0		
First Year Start-Up (expensed in yr 1)			0		
Reserve Funds			5,410		

			140,650	ok	

Revenues

Energy Pmt	$0.0753	/kWh at	2.00%	/year beginning in year	1
Energy Pmt	$0.0500	/kWh at	2.00%	/year beginning in year	21
Capacity Pmt	$0.00	/kWh at	1.00%	/year	

Earnings		100 MW IPP - 33.8 cf, Class 4, no PTC				09/14/06	6:17 PM				
All figures in $thousands.											
	0	1	2	3	4	5	6	7	8	9	10
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Revenues											
Energy Payment		22,295	22,741	23,196	23,660	24,133	24,616	25,108	25,610	26,123	26,645
Capacity Payment		0	0	0	0	0	0	0	0	0	0
Interest on Reserves		162	162	162	162	162	162	162	162	162	162
Total Revenues		22,458	22,904	23,358	23,822	24,296	24,778	25,271	25,773	26,285	26,807
Operating Costs											
Operations & Maintenance - fixed		2,067	2,119	2,172	2,226	2,282	2,339	2,397	2,457	2,518	2,581
Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
Site Owner Land Rent		333	342	350	359	368	377	387	396	406	416
Property Tax		1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320
Insurance		1,353	1,387	1,421	1,457	1,493	1,531	1,569	1,608	1,648	1,690
Major Maintenance & Overhauls		500	513	525	538	552	566	580	594	609	624
Total Operating Costs		5,573	5,680	5,789	5,900	6,015	6,132	6,253	6,376	6,502	6,632
Operating Income		16,884	17,224	17,570	17,922	18,281	18,646	19,018	19,397	19,783	20,176
Other Expenses											
Interest on Loan #1		6,892	6,618	6,324	6,010	5,674	5,315	4,930	4,518	4,078	3,607
Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
Depreciation		26,400	42,240	25,344	15,206	15,206	7,603	0	0	0	0
Repair Depreciation		0	0	0	0	0	0	0	0	0	0
Amortization		741	233	233	233	233	131	131	131	131	131
Total Other Expenses		34,033	49,091	31,901	21,449	21,113	13,049	5,061	4,650	4,209	3,738
Before-Tax Profits		(17,148)	(31,867)	(14,331)	(3,527)	(2,833)	5,597	13,957	14,747	15,573	16,437
40.00% Income Tax Paid (Benefit Rec'd)		(6,859)	(12,747)	(5,733)	(1,411)	(1,133)	2,239	5,583	5,899	6,229	6,575
Investment Tax Credit Received		0	0								
Production Tax Credits Received		0	0	0	0	0	0	0	0	0	0
After-Tax Profits		(10,289)	(19,120)	(8,599)	(2,116)	(1,700)	3,358	8,374	8,848	9,344	9,862

Earnings — **100 MW IPP - 33.8 cf, Class 4, no PTC** — **09/14/06** — **6:17 PM**

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Revenues											
	Energy Payment	27,178	27,722	28,276	28,842	29,418	30,007	30,607	31,219	31,843	32,480	0
	Capacity Payment	0	0	0	0	0	0	0	0	0	0	0
	Interest on Reserves	162	162	162	162	162	0	0	0	0	0	0
	Total Revenues	27,340	27,884	28,438	29,004	29,581	30,007	30,607	31,219	31,843	32,480	0
	Operating Costs											
	Operations & Maintenance - fixed	2,646	2,712	2,780	2,849	2,921	2,994	3,068	3,145	3,224	3,304	0
	Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent	427	437	448	460	471	483	495	507	520	533	0
	Property Tax	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	0
	Insurance	1,732	1,775	1,820	1,865	1,912	1,960	2,009	2,059	2,110	2,163	0
	Major Maintenance & Overhauls	640	656	672	689	706	724	742	761	780	799	0
	Total Operating Costs	6,765	6,901	7,040	7,183	7,330	7,480	7,634	7,792	7,954	8,120	0
	Operating Income	20,576	20,983	21,398	21,821	22,251	22,527	22,973	23,427	23,890	24,361	0
	Other Expenses											
	Interest on Loan #1	3,103	2,563	1,986	1,368	707	0	0	0	0	0	0
	Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
	Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Amortization	131	131	131	131	131	0	0	0	0	0	0
	Total Other Expenses	3,234	2,694	2,117	1,499	839	0	0	0	0	0	0
	Before-Tax Profits	17,342	18,289	19,281	20,321	21,412	22,527	22,973	23,427	23,890	24,361	0
40.00%	Income Tax Paid (Benefit Rec'd)	6,937	7,315	7,712	8,128	8,565	9,011	9,189	9,371	9,556	9,744	0
	Investment Tax Credit Received											
	Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits	10,405	10,973	11,569	12,193	12,847	13,516	13,784	14,056	14,334	14,616	0

Appendix I (cont.)

Cash Flow & COE 100 MW IPP - 33.8 cf, Class 4, no PTC 09/14/06 6:17 PM

All figures in $thousands.	0	1	2	3	4	5	6	7	8	9	10
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Before-Tax Profits		(17,148)	(31,867)	(14,331)	(3,527)	(2,833)	5,597	13,957	14,747	15,573	16,437
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		26,400	42,240	25,344	15,206	15,206	7,603	0	0	0	0
Amortization		741	233	233	233	233	131	131	131	131	131
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		27,141	42,473	25,577	15,439	15,439	7,735	131	131	131	131
Subtract Off:											
Loan #1 Principal		3,918	4,192	4,486	4,800	5,136	5,495	5,880	6,291	6,732	7,203
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		3,918	4,192	4,486	4,800	5,136	5,495	5,880	6,291	6,732	7,203
Before-Tax Cash		6,075	6,414	6,760	7,112	7,471	7,836	8,208	8,587	8,973	9,366
Taxes Payable (Benefit Received)		(6,859)	(12,747)	(5,733)	(1,411)	(1,133)	2,239	5,583	5,899	6,229	6,575
Investment Tax Credit		0	0								
Production Tax Credit		0	0	0	0	0	0	0	0	0	0
After-Tax Cash	(42,195)	12,934	19,161	12,492	8,523	8,604	5,597	2,626	2,688	2,744	2,791

After-tax IRR 23.803%
using starting estimate of 12.000% .
Net Present Value 29,218 , using 10.00% as discount rate for developer
Payback 3

	0	1	2	3	4	5	6	7	8	9	10
		1	1	1	0	0	0	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value of money [and discount factor] and excluding tax credits, tax losses, tax payments)
Minimum 14.40% <-- -- Reset both as years of projec
Average 29.90%

	0	1	2	3	4	5	6	7	8	9	10
Before-Tax Cash and Equity Investmen	(42,195)	6,075	6,414	6,760	7,112	7,471	7,836	8,208	8,587	8,973	9,366
BT Cash to Equity Investment (not discounted)		14.40%	15.20%	16.02%	16.86%	17.71%	18.57%	19.45%	20.35%	21.27%	22.20%

		1	2	3	4	5	6	7	8	9	10
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	22,295	22,741	23,196	23,660	24,133	24,616	25,108	25,610	26,123	26,645
	Capacity	0	0	0	0	0	0	0	0	0	0
Total (thousands)		22,295	22,741	23,196	23,660	24,133	24,616	25,108	25,610	26,123	26,645

Net Present Value 243,303 , using 8.500% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 25,710 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 5.50% for tax-free coop; 8.5% for IOU) *

lev COE/kWh $0.0868 in nominal terms of 2005
lev COE/kWh $0.0847 in nominal terms of 2004

04/30/01 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

1st-yr Cost $0.0753
Constant $ NPV 243,303 , as nominal
Constant $ levelized 20,961 , using 5.854% = (1 + 0.085)/(1 + 0.025) - 1
lev COE/kWh $0.0708 in constant terms of 2005
lev COE/kWh $0.0691 in constant terms of 2004

Cash Flow & COE 100 MW IPP - 33.8 cf, Class 4, no PTC 09/14/06 6:17 PM

All figures in $thousands.	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020	17 2021	18 2022	19 2023	20 2024	21 2025
Before-Tax Profits	17,342	18,289	19,281	20,321	21,412	22,527	22,973	23,427	23,890	24,361	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	131	131	131	131	131	0	0	0	0	0	0
Released from Reserve	0	0	0	0	5,410	0	0	0	0	0	0
Total Additions	131	131	131	131	5,541	0	0	0	0	0	0
Subtract Off:											
Loan #1 Principal	7,707	8,247	8,824	9,442	10,103	0	0	0	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	7,707	8,247	8,824	9,442	10,103	0	0	0	0	0	0
Before-Tax Cash	9,766	10,173	10,588	11,011	16,851	22,527	22,973	23,427	23,890	24,361	0
Taxes Payable (Benefit Received)	6,937	7,315	7,712	8,128	8,565	9,011	9,189	9,371	9,556	9,744	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	2,829	2,858	2,876	2,882	8,286	13,516	13,784	14,056	14,334	14,616	0
	0	0	0	0	0	0	0	0	0	0	0
:t life varies.											
Before-Tax Cash and Equity Investmen	9,766	10,173	10,588	11,011	16,851	22,527	22,973	23,427	23,890	24,361	0
BT Cash to Equity Investment (not disc	23.14%	24.11%	25.09%	26.09%	39.94%	53.39%	54.44%	55.52%	56.62%	57.73%	0.00%

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%
Electric Revenues:	Energy	27,178	27,722	28,276	28,842	29,418	30,007	30,607	31,219	31,843	32,480	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)		27,178	27,722	28,276	28,842	29,418	30,007	30,607	31,219	31,843	32,480	0

*To figure Discount rate:

Utility debt	50.00%	6.50%
preferred	5.00%	6.30%
common	45.00%	11.00%

8.52% weighted average cost of capital

Debt Redemption & PTC			**100 MW IPP - 33.8 cf, Class 4, no PTC**				**09/14/06**	**6:17 PM**				
All figures in $thousands.												
		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Loan #1		98,455	at 7.000%	for 15 years	level mortgage -- with ONE payment/year							
Beginning Balance			98,455	94,537	90,345	85,859	81,059	75,924	70,429	64,549	58,257	51,525
Interest			6,892	6,618	6,324	6,010	5,674	5,315	4,930	4,518	4,078	3,607
Loan Guarantee Fees			0	0	0	0	0	0	0	0	0	0
Principal			3,918	4,192	4,486	4,800	5,136	5,495	5,880	6,291	6,732	7,203
Total			10,810	10,810	10,810	10,810	10,810	10,810	10,810	10,810	10,810	10,810
Available Cash: Operating Income			16,884	17,224	17,570	17,922	18,281	18,646	19,018	19,397	19,783	20,176
PTC monetization, if any			0	0	0	0	0	0	0	0	0	0
Total Debt Service			10,810	10,810	10,810	10,810	10,810	10,810	10,810	10,810	10,810	10,810
Debt Coverage Ratio			1.562	1.593	1.625	1.658	1.691	1.725	1.759	1.794	1.830	1.866
Average Ratio	1.800		not counting last partial year									
Minimum Ratio	1.562											
Loan #2		0	at 7.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			0	0	0	0	0	0	0	0	0	0
Interest			0	0	0	0	0	0	0	0	0	0
Principal			0	0	0	0	0	0	0	0	0	0
Total			0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?	yes		, where yes means pay senior debt first or no is pay both loans together.									
Available Cash: Op Income & PTC, if monetized			6,075	6,414	6,760	7,112	7,471	7,836	8,208	8,587	8,973	9,366
Total Debt Service			0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	3		Select 1 = escalating rate by formula or 2 = customized rate or 3 = TURNED OFF for no credit at all.								PTC expires 12/31/2007, unless extended.	
	ok											
1 Escalating Rate		{	Starting Credit	$0.019	/kWh;	Start Year	1		yr 1 fraction	1.000	}	
(enter data on right;		{	Escal Rate	2.500%	year;	Last Year	10				}	
(calc'd rate in line 158;		{									}	
(selected rate in line 163.)		{	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
2 Customized Absolute			0	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854
	$/kWh											
Active Credit:	$thous		0	0	0	0	0	0	0	0	0	0

Debt Redemption & PTC — 100 MW IPP - 33.8 cf, Class 4, no PTC — 09/14/06 — 6:17 PM

All figures in $thousands.

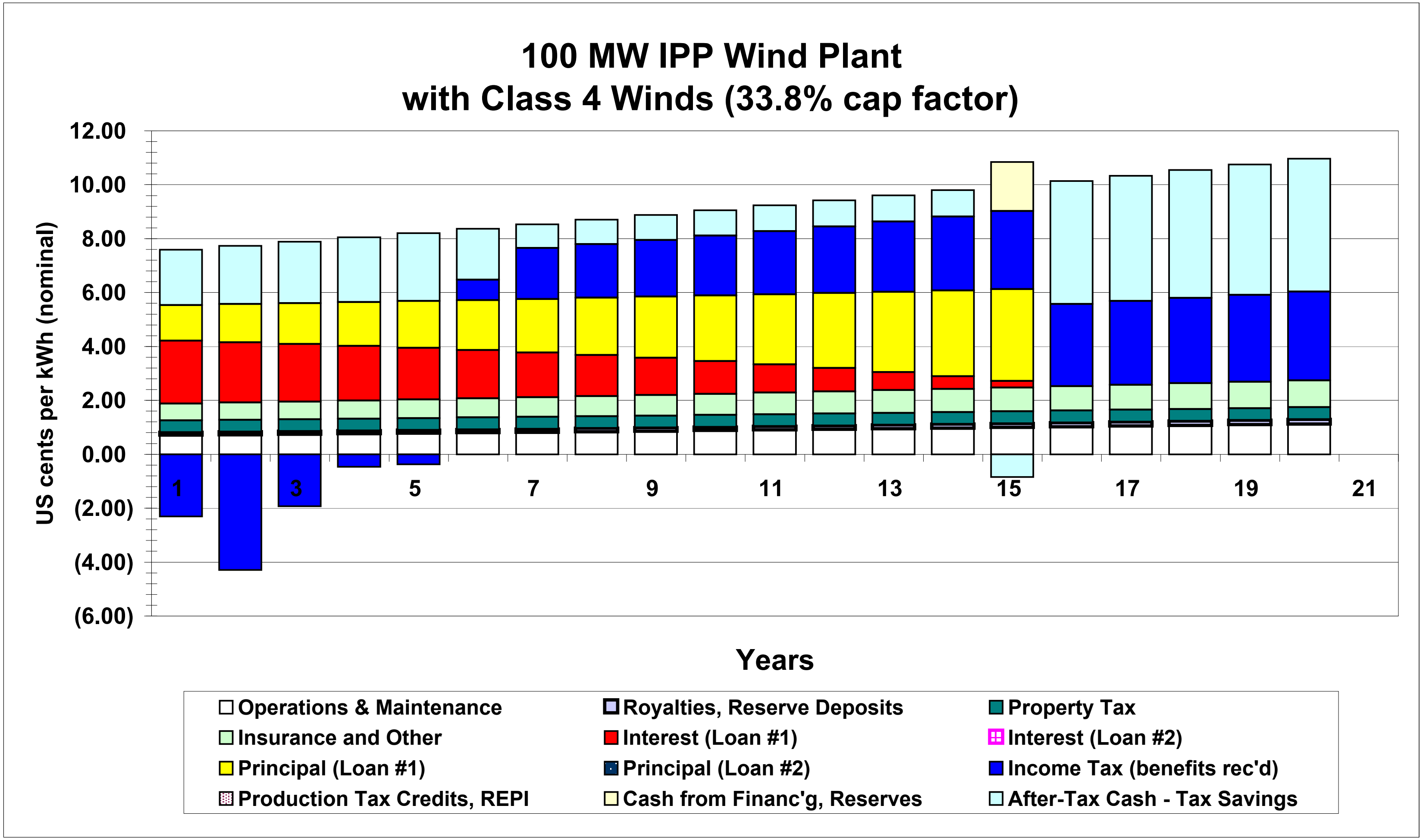
		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Loan #1												
Beginning Balance		44,322	36,615	28,368	19,544	10,103	0	0	0	0	0	0
Interest		3,103	2,563	1,986	1,368	707	0	0	0	0	0	0
Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
Principal		7,707	8,247	8,824	9,442	10,103	0	0	0	0	0	0
Total		10,810	10,810	10,810	10,810	10,810	0	0	0	0	0	0
Available Cash: Operating Income		20,576	20,983	21,398	21,821	22,251	22,527	22,973	23,427	23,890	24,361	0
PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		10,810	10,810	10,810	10,810	10,810	0	0	0	0	0	0
Debt Coverage Ratio		1.903	1.941	1.979	2.019	2.058	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	1.800											
Minimum Ratio	1.562											
Loan #2												
Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?												
Available Cash: Op Income & PTC, if mo		9,766	10,173	10,588	11,011	11,441	22,527	22,973	23,427	23,890	24,361	0
Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	3											
	ok											
1 Escalating Rate (enter data on right; (calc'd rate in line 158; (selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2 Customized Absolute		7,026	0	0	0	0	0	0	0	0	0	0
	$/kWh											
Active Credit:	$thous	0	0	0	0	0	0	0	0	0	0	0

Appendix I (cont.)

Graph Points — **100 MW IPP - 33.8 cf, Class 4, no PTC** — **09/14/06** — **6:17 PM**

		1	2	3	4	5	6	7	8	9	10
	296,088,000 kWh/year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Cost Components										
	in nominal US cents/kWh (money of the year)										
	Revenues	7.585	7.735	7.889	8.046	8.206	8.369	8.535	8.704	8.877	9.054
1	Operations & Maintenance	0.698	0.716	0.733	0.752	0.771	0.790	0.810	0.830	0.851	0.872
2	Royalties, Reserve Deposits	0.113	0.115	0.118	0.121	0.124	0.127	0.131	0.134	0.137	0.141
3	Property Tax	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446
4	Insurance and Other	0.626	0.641	0.658	0.674	0.691	0.708	0.726	0.744	0.763	0.782
5	Interest (Loan #1)	2.328	2.235	2.136	2.030	1.916	1.795	1.665	1.526	1.377	1.218
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	1.323	1.416	1.515	1.621	1.735	1.856	1.986	2.125	2.274	2.433
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	(2.317)	(4.305)	(1.936)	(0.477)	(0.383)	0.756	1.885	1.992	2.104	2.221
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	2.052	2.166	2.283	2.402	2.523	1.890	0.887	0.908	0.927	0.943
	Energy Revenues (with neg tax added as positive)	7.585	7.735	7.889	8.046	8.206	8.369	8.535	8.704	8.877	9.054
check	Energy Revenues	7.530	7.681	7.834	7.991	8.151	8.314	8.480	8.650	8.823	8.999
	Interest on Reserves	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055
check	Total	7.585	7.735	7.889	8.046	8.206	8.369	8.535	8.704	8.877	9.054

Graph Points		100 MW IPP - 33.8 cf, Class 4, no PTC				09/14/06	6:17 PM					
		11	12	13	14	15	16	17	18	19	20	21
	296,088,000 kWh/year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Cost Components in nominal US cents/kWh (money of the											
	Revenues	9.234	9.417	9.605	9.796	9.990	10.134	10.337	10.544	10.755	10.970	0.000
1	Operations & Maintenance	0.894	0.916	0.939	0.962	0.986	1.011	1.036	1.062	1.089	1.116	0.000
2	Royalties, Reserve Deposits	0.144	0.148	0.151	0.155	0.159	0.163	0.167	0.171	0.176	0.180	0.000
3	Property Tax	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.000
4	Insurance and Other	0.801	0.821	0.842	0.863	0.884	0.906	0.929	0.952	0.976	1.000	0.000
5	Interest (Loan #1)	1.048	0.866	0.671	0.462	0.239	0.000	0.000	0.000	0.000	0.000	0.000
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	2.603	2.785	2.980	3.189	3.412	0.000	0.000	0.000	0.000	0.000	0.000
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	2.343	2.471	2.605	2.745	2.893	3.043	3.104	3.165	3.227	3.291	0.000
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	1.827	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	0.956	0.965	0.971	0.973	(0.856)	4.565	4.655	4.747	4.841	4.936	0.000
	Energy Revenues (with neg tax added as positive)	9.234	9.417	9.605	9.796	9.990	10.134	10.337	10.544	10.755	10.970	0.000
check	Energy Revenues	9.179	9.363	9.550	9.741	9.936	10.134	10.337	10.544	10.755	10.970	0.000
	Interest on Reserves	0.055	0.055	0.055	0.055	0.055	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	9.234	9.417	9.605	9.796	9.990	10.134	10.337	10.544	10.755	10.970	0.000


100 MW IPP Wind Plant
with Class 4 Winds (33.8% cap factor)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
US cents per kWh (nominal)
1
3
5
7
9
11
13
15
17
19
21
Years
Operations & Maintenance
Royalties, Reserve Deposits
Property Tax
Insurance and Other
Interest (Loan #1)
Interest (Loan #2)
Principal (Loan #1)
Principal (Loan #2)
Income Tax (benefits rec'd)
Production Tax Credits, REPI
Cash from Financ'g, Reserves
After-Tax Cash - Tax Savings

SUMMARY PAGE 100 MW IPP - 33.8 cf, Class 4, w/ PTC 09/14/06 6:51 PM

File: 0914IPPWind2004_withPTC.xls

Construction and Development Assumptions and Operating Results

All figures are in thousands of U.S. dollars.

Capital				
Total Project Cost	140,020			
Start Date	2005	at 100% for year 1		
Project Description	100 MW Wind Farm, using Class 4 Winds owned by taxable IPP using limited recourse Project Finance			
Finance				
Debt	84,012	at 7.000%	for 15 years	
Secondary Debt	0	at 7.500%	for 18 years	
Equity	56,008			

Total	140,020			
Operations				
Net Rated Capacity	100,000	kW, using	1,500	kW-rated turbines
Actual Hours/Year	8,760	hours/year	67	turbines
Wind Resource	Class 4 Winds			
Net Capacity Factor	33.80%			
Plant Annual Electricity	296,088	thou kWh/year		
Contract Term	20	years		
Operations & Maintenance - fixed	20.67	/kW or	$31,005	/turbine - year
escalating at	2.50%	/year	equiv to 0.698 c/kWh	
Operations & Maintenance - var.	$0.000	/kWh		
escalating at	2.50%	/year		
For land payment, select 1 = percentage revenues, 2 = fixed rent			2	ok
Site Owner Royalty *not used*	0.00%	of revenues		
Site Owner Land Rent *used*	$333.33	thous/year		
escalating at	2.50%	/year	equiv to 0.113 c/kWh	
Property Tax	1.000%	of depreciable base		
escalating at	0.00%	/year		
where base depreciates	0.00%	/year, till hits	0.0%	
Insurance	1.025%	of depreciable base, esc. at	2.50%	/year
Major Maintenance & Overhauls	$500.00	thous/year or	$7,500	/turbine - year
escalating at	2.50%	/year	equiv to 0.169 c/kWh	
			--	
Inflation	2.50%	/year		
Interest Earned on Reserves	3.00%	/year; Interest on Work. Cap	0.50%	/year

Capital Cost per kW installed capacity			1,400	[140020 / 100]
Cost per Annual kWh			$0.47	[140020 / 296088]
			--	
			--	
			--	
RETURNS				
using a discount rate of			10.00%	
1	Pre-tax Unleveraged IRR		10.116%	over 20 years
	Net Present Value		1,097	using 10%
	Payback		9	years
2	After-tax Leveraged IRR		28.053%	over 20 years Target 17%
	Net Present Value		46,870	using 10%
	Payback		3	years
2a	Cash-on-Cash Return, excluding PTC		19.220%	average
	(before-tax cash on equity, non-discounted)		9.247%	minimum
COST OF UTILITY ENERGY		+---- -->	$0.0670	/kWh - first year
in currency of 2005		+---- -->	$0.0773	/kWh - nominal levelized
		+---- -->	$0.0630	/kWh - constant$ levelized
in currency of the year		+---- -->	$0.0500	/kWh - year 21
in currency of 2004		+---- -->	$0.0754	/kWh - nominal levelized
		+---- -->	$0.0615	/kWh - constant$ levelized
using a discount rate of		8.50%	nominal	
		5.85%	constant (with no inflation)	
DEBT COVERAGE	--			Min Target
Senior Debt Coverage ratio:			1.800 average	1.80 times
			1.561 minimum	1.50 times
Secondary Debt Coverage ratio:			-- average	
--			-- minimum	
Equipment Overhaul Reserve & Drawdown?		no, not undertaken		ok
Every 10 years, at 0 %, 0%, and 0% of plant cost.				

01/21/2005 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance; pg 2 (Sources): capital costs & selected financial incl'g Revenues; pg 5 (Cash Flow): COE disc rate; pg 7 (Debt): PTC details; pg 9 (Work Sheet #1): depreciation; pg 11 (Work Sheet #2): senior debt; pg 13 (Work Sheet #3): secondary debt.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100 MW, using Class 4 Winds winds with a 33.8% capacity factor. Contract term is 20 years.
Capital Cost is $1260 /kW. O&M is $20.67 /kW and $0 /kWh and $500 thousand per year.

This Project TAKES the 10-year Section 45 Production Tax Credit.
Financing is 60% senior debt at 7% for 15 years and 0% secondary debt and 40% equity.
Sales Tax is $ 0 thousands. Property tax is 1 % of depreciable base, escalating at inflation, but with base depreciating at 0% per year till hits 0%.

Sources and Uses of Funds

100 MW IPP - 33.8 cf, Class 4, w/ PTC 09/14/06 6:51 PM

Uses of Funds

in thousands of mixed-year dollars

	Rotor Assembly			16,502		
	Drive Train & Nacelle			37,518		
	Controls, Safety System			667		
	Tower			6,733		
	Market Adjustment			20,000		
	Foundations, Transport, Roads			11,896		
	Assembly, Interconnect, Permits, Engr			13,998		
	Permit/Environmental Adjustment			1,886		
	Manufacturing Uncertainty			10,800		
6,000	Construction Contingency			6,000		
	Home Office Overhead			0		--
	Total	1,260	/kW		126,000	*
	Sales Tax	0			0	*
	Construction Financing	6,000			6,000	*
	(estimated as $120 mil * 10% * 12 mos * 50% for level draw)					
	Construction Insur.				0	*
	Land				0	
	Initial Working Capital: First Year				0	
	Debt Financing Fees	1,680			1,700	--
	(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)					
	Equity Financing Fees	1,680			1,700	--
	(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)					--
	Debt Service Reserve Fund	4,612			4,620	--
	Working Capital, Operating Reserve	517			0	
	Equipment Repair Reserve Initial Pmt				0	

					140,020	

Misc.

Start Year	2005	
Year 1 Calendar Fraction	100.00%	
Factor w/ 2 debt pmts/yr	100.00%	
Depreciation Rate #1	20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%	
Depreciation Rate #2	5%, 9.5%, 8.55%, 7.7%, 6.93%, 6.23%, 5.9% 5.9%, 5.91%, 5.9%, 5.91%, 5.9%, 5.91%, 5.9% 5.91%, 2.95%, 0%, 0%, 0%, 0%, 0%	
Equity Amortization:	40% @ 5 years, 40% @ 1 year, and 20% @ no write-off	

Sources of Funds

60.00%	Debt	84,012	at 7.000%	for 15 years	level mortgage
0.00%	Second Loan	0	at 7.500%	for 18 years	level mortgage
40.00%	Equity	56,008			
----------		----------		--	
100.00%		140,020		--	
				--	

Taxes

Marginal Tax Rate:	Federal	35.00%	corporate federal rate is 35%,
	State	7.69%	corporate "average" state is 7.69%,
	Combined	40.00%	
Investment Tax Credit		0.00%	

Depreciation

Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.

Depreciation Class Life #1	5	years; Percent at Life #1		100.00%	ok
Depreciation Class Life #2	15	years; Percent at Life #2		0.00%	ok
Amortization for Equity Finc'g Fees	40.00%		40.00%	20.00%	(See B207 on Sheet2.)

Tax Treatment

Sum of Depreciable Items		132,000	including sales tax		
Primary System Depreciable Base			132,000	5	years
less Tax Credit Adjustmt	50.00%	0			
Primary System Depreciable Base		132,000			
Other Depreciable Base			0	15	years
Amortization over Sr Debt's Life			1,700	15	years
Amortization over Second Debt's Life			0	18	years
5 years' Amortization			680		
1 years' Amortization			680		
No Write-Off			340		
Land			0		
First Year Start-Up (expensed in yr 1)			0		
Reserve Funds			4,620		

			140,020	ok	

Revenues

Energy Pmt	$0.0670	/kWh at	2.00%	/year beginning in year	1
Energy Pmt	$0.0500	/kWh at	2.00%	/year beginning in year	21
Capacity Pmt	$0.00	/kWh at	1.00%	/year	

Earnings **100 MW IPP - 33.8 cf, Class 4, w/ PTC** **09/14/06** **6:51 PM**

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Revenues											
	Energy Payment		19,838	20,235	20,639	21,052	21,473	21,903	22,341	22,788	23,243	23,708
	Capacity Payment		0	0	0	0	0	0	0	0	0	0
	Interest on Reserves		139	139	139	139	139	139	139	139	139	139
	Total Revenues		19,976	20,373	20,778	21,191	21,612	22,041	22,479	22,926	23,382	23,847
	Operating Costs											
	Operations & Maintenance - fixed		2,067	2,119	2,172	2,226	2,282	2,339	2,397	2,457	2,518	2,581
	Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent		333	342	350	359	368	377	387	396	406	416
	Property Tax		1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320
	Insurance		1,353	1,387	1,421	1,457	1,493	1,531	1,569	1,608	1,648	1,690
	Major Maintenance & Overhauls		500	513	525	538	552	566	580	594	609	624
	Total Operating Costs		5,573	5,680	5,789	5,900	6,015	6,132	6,253	6,376	6,502	6,632
	Operating Income		14,403	14,694	14,989	15,290	15,597	15,909	16,227	16,550	16,880	17,215
	Other Expenses											
	Interest on Loan #1		5,881	5,647	5,396	5,128	4,842	4,535	4,207	3,856	3,480	3,078
	Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
	Depreciation		26,400	42,240	25,344	15,206	15,206	7,603	0	0	0	0
	Repair Depreciation		0	0	0	0	0	0	0	0	0	0
	Amortization		929	249	249	249	249	113	113	113	113	113
	Total Other Expenses		33,210	48,136	30,990	20,584	20,298	12,252	4,320	3,969	3,593	3,191
	Before-Tax Profits		(18,807)	(33,443)	(16,000)	(5,294)	(4,701)	3,657	11,907	12,581	13,286	14,024
40.00%	Income Tax Paid (Benefit Rec'd)		(7,523)	(13,377)	(6,400)	(2,118)	(1,880)	1,463	4,763	5,033	5,315	5,610
	Investment Tax Credit Received		0	0								
	Production Tax Credits Received		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
	After-Tax Profits		(5,659)	(14,299)	(3,690)	2,882	3,389	8,559	13,668	14,236	14,826	15,440

Earnings 100 MW IPP - 33.8 cf, Class 4, w/ PTC 09/14/06 6:51 PM

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Revenues											
	Energy Payment	24,182	24,666	25,159	25,662	26,176	26,699	27,233	27,778	28,333	28,900	0
	Capacity Payment	0	0	0	0	0	0	0	0	0	0	0
	Interest on Reserves	139	139	139	139	139	0	0	0	0	0	0
	Total Revenues	24,321	24,805	25,298	25,801	26,314	26,699	27,233	27,778	28,333	28,900	0
	Operating Costs											
	Operations & Maintenance - fixed	2,646	2,712	2,780	2,849	2,921	2,994	3,068	3,145	3,224	3,304	0
	Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent	427	437	448	460	471	483	495	507	520	533	0
	Property Tax	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	0
	Insurance	1,732	1,775	1,820	1,865	1,912	1,960	2,009	2,059	2,110	2,163	0
	Major Maintenance & Overhauls	640	656	672	689	706	724	742	761	780	799	0
	Total Operating Costs	6,765	6,901	7,040	7,183	7,330	7,480	7,634	7,792	7,954	8,120	0
	Operating Income	17,556	17,904	18,258	18,618	18,984	19,219	19,599	19,986	20,380	20,780	0
	Other Expenses											
	Interest on Loan #1	2,647	2,187	1,694	1,167	603	0	0	0	0	0	0
	Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
	Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Amortization	113	113	113	113	113	0	0	0	0	0	0
	Total Other Expenses	2,761	2,300	1,808	1,281	717	0	0	0	0	0	0
	Before-Tax Profits	14,795	15,603	16,450	17,337	18,268	19,219	19,599	19,986	20,380	20,780	0
40.00%	Income Tax Paid (Benefit Rec'd)	5,918	6,241	6,580	6,935	7,307	7,688	7,840	7,994	8,152	8,312	0
	Investment Tax Credit Received											
	Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits	8,877	9,362	9,870	10,402	10,961	11,531	11,759	11,992	12,228	12,468	0

Cash Flow & COE 100 MW IPP - 33.8 cf, Class 4, w/ PTC 09/14/06 6:51 PM

All figures in $thousands.	0	1	2	3	4	5	6	7	8	9	10
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Before-Tax Profits		(18,807)	(33,443)	(16,000)	(5,294)	(4,701)	3,657	11,907	12,581	13,286	14,024
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		26,400	42,240	25,344	15,206	15,206	7,603	0	0	0	0
Amortization		929	249	249	249	249	113	113	113	113	113
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		27,329	42,489	25,593	15,456	15,456	7,717	113	113	113	113
Subtract Off:											
Loan #1 Principal		3,343	3,577	3,828	4,096	4,382	4,689	5,017	5,368	5,744	6,146
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		3,343	3,577	3,828	4,096	4,382	4,689	5,017	5,368	5,744	6,146
Before-Tax Cash		5,179	5,470	5,765	6,066	6,373	6,685	7,003	7,326	7,656	7,991
Taxes Payable (Benefit Received)		(7,523)	(13,377)	(6,400)	(2,118)	(1,880)	1,463	4,763	5,033	5,315	5,610
Investment Tax Credit		0	0								
Production Tax Credit		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
After-Tax Cash	(56,008)	18,328	24,613	18,076	14,242	14,463	11,587	8,764	8,981	9,195	9,407

After-tax IRR 28.053%
using starting estimate of 12.000% .
Net Present Value 46,870 , using 10.00% as discount rate for developer
Payback 3

	0	1	2	3	4	5	6	7	8	9	10
		1	1	1	0	0	0	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value of money [and discount factor] and excluding tax credits, tax losses, tax payments)
Minimum 9.25% <-- -- Reset both as years of project
Average 19.22%

	0	1	2	3	4	5	6	7	8	9	10
Before-Tax Cash and Equity Investmen	(56,008)	5,179	5,470	5,765	6,066	6,373	6,685	7,003	7,326	7,656	7,991
BT Cash to Equity Investment (not discounted)		9.25%	9.77%	10.29%	10.83%	11.38%	11.94%	12.50%	13.08%	13.67%	14.27%

		1	2	3	4	5	6	7	8	9	10
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	19,838	20,235	20,639	21,052	21,473	21,903	22,341	22,788	23,243	23,708
	Capacity	0	0	0	0	0	0	0	0	0	0
Total (thousands)		19,838	20,235	20,639	21,052	21,473	21,903	22,341	22,788	23,243	23,708

Net Present Value 216,485 , using 8.500% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 22,876 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 5.50% for tax-free coop; 8.5% for IOU) *

lev COE/kWh $0.0773 in nominal terms of 2005
lev COE/kWh $0.0754 in nominal terms of 2004

04/30/01 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

1st-yr Cost $0.0670
Constant $ NPV 216,485 , as nominal
Constant $ levelized 18,651 , using 5.854% = (1 + 0.085)/(1 + 0.025) - 1
lev COE/kWh $0.0630 in constant terms of 2005
lev COE/kWh $0.0615 in constant terms of 2004

Cash Flow & COE **100 MW IPP - 33.8 cf, Class 4, w/ PTC** **09/14/06** **6:51 PM**

All figures in $thousands.	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020	17 2021	18 2022	19 2023	20 2024	21 2025
Before-Tax Profits	14,795	15,603	16,450	17,337	18,268	19,219	19,599	19,986	20,380	20,780	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	113	113	113	113	113	0	0	0	0	0	0
Released from Reserve	0	0	0	0	4,620	0	0	0	0	0	0
Total Additions	113	113	113	113	4,733	0	0	0	0	0	0
Subtract Off:											
Loan #1 Principal	6,577	7,037	7,530	8,057	8,621	0	0	0	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	6,577	7,037	7,530	8,057	8,621	0	0	0	0	0	0
Before-Tax Cash	8,332	8,680	9,034	9,394	14,380	19,219	19,599	19,986	20,380	20,780	0
Taxes Payable (Benefit Received)	5,918	6,241	6,580	6,935	7,307	7,688	7,840	7,994	8,152	8,312	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	2,414	2,438	2,454	2,459	7,073	11,531	11,759	11,992	12,228	12,468	0
	0	0	0	0	0	0	0	0	0	0	0
:t life varies.											
Before-Tax Cash and Equity Investmen	8,332	8,680	9,034	9,394	14,380	19,219	19,599	19,986	20,380	20,780	0
BT Cash to Equity Investment (not disc	14.88%	15.50%	16.13%	16.77%	25.68%	34.31%	34.99%	35.68%	36.39%	37.10%	0.00%

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%
Electric Revenues:	Energy	24,182	24,666	25,159	25,662	26,176	26,699	27,233	27,778	28,333	28,900	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)		24,182	24,666	25,159	25,662	26,176	26,699	27,233	27,778	28,333	28,900	0

*To figure Discount rate:

Utility debt	50.00%	6.50%
preferred	5.00%	6.30%
common	45.00%	11.00%

8.52% weighted average cost of capital

Debt Redemption & PTC — **100 MW IPP - 33.8 cf, Class 4, w/ PTC** — **09/14/06** — **6:51 PM**

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Loan #1		84,012	at 7.000%	for 15 years	level mortgage -- with ONE payment/year							
Beginning Balance			84,012	80,669	77,092	73,264	69,168	64,786	60,097	55,080	49,711	43,967
Interest			5,881	5,647	5,396	5,128	4,842	4,535	4,207	3,856	3,480	3,078
Loan Guarantee Fees			0	0	0	0	0	0	0	0	0	0
Principal			3,343	3,577	3,828	4,096	4,382	4,689	5,017	5,368	5,744	6,146
Total			9,224	9,224	9,224	9,224	9,224	9,224	9,224	9,224	9,224	9,224
Available Cash: Operating Income			14,403	14,694	14,989	15,290	15,597	15,909	16,227	16,550	16,880	17,215
PTC monetization, if any			0	0	0	0	0	0	0	0	0	0
Total Debt Service			9,224	9,224	9,224	9,224	9,224	9,224	9,224	9,224	9,224	9,224
Debt Coverage Ratio			1.561	1.593	1.625	1.658	1.691	1.725	1.759	1.794	1.830	1.866
Average Ratio	1.800		not counting last partial year									
Minimum Ratio	1.561											
Loan #2		0	at 7.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			0	0	0	0	0	0	0	0	0	0
Interest			0	0	0	0	0	0	0	0	0	0
Principal			0	0	0	0	0	0	0	0	0	0
Total			0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?	yes		, where yes means pay senior debt first or no is pay both loans together.									
Available Cash: Op Income & PTC, if monetized			5,179	5,470	5,765	6,066	6,373	6,685	7,003	7,326	7,656	7,991
Total Debt Service			0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	1		Select 1 = escalating rate by formula or 2 = customized rate or 3 = TURNED OFF for no credit at all.							PTC expires 12/31/2007, unless extended.		
	ok											
1 Escalating Rate		{ Starting Credit		$0.019 /kWh;	Start Year		1		yr 1 fraction	1.000 }		
(enter data on right;		{ Escal Rate		2.500% year;	Last Year		10			}		
(calc'd rate in line 158;		{								}		
(selected rate in line 163.)		{	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
2 Customized Absolute			0	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854
	$/kWh		0.01900	0.01948	0.01996	0.02046	0.02097	0.02150	0.02203	0.02259	0.02315	0.02373
Active Credit:	$thous		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026

Debt Redemption & PTC

100 MW IPP - 33.8 cf, Class 4, w/ PTC 09/14/06 6:51 PM

All figures in $thousands.

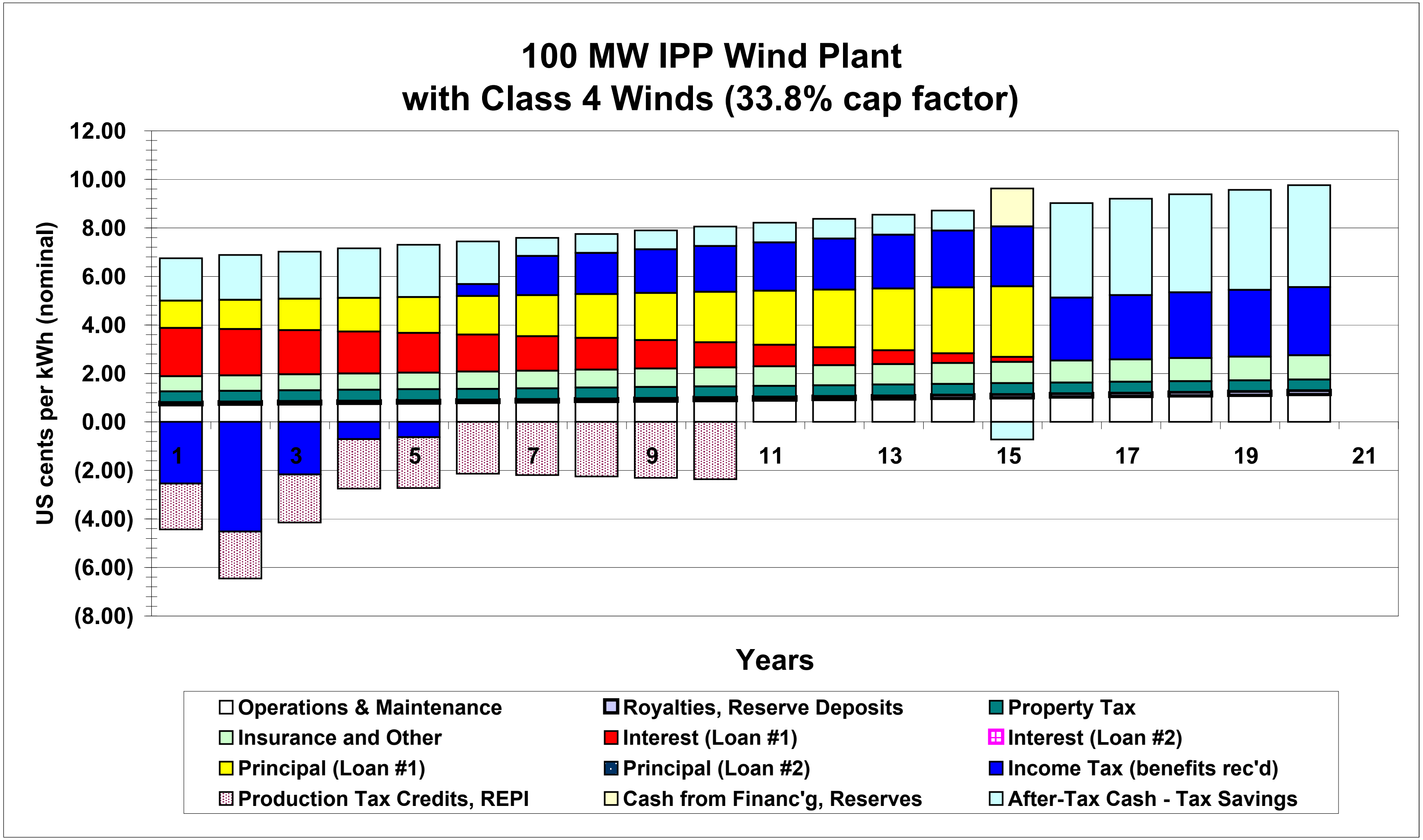
		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Loan #1												
Beginning Balance		37,820	31,244	24,207	16,677	8,621	0	0	0	0	0	0
Interest		2,647	2,187	1,694	1,167	603	0	0	0	0	0	0
Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
Principal		6,577	7,037	7,530	8,057	8,621	0	0	0	0	0	0
Total		9,224	9,224	9,224	9,224	9,224	0	0	0	0	0	0
Available Cash: Operating Income		17,556	17,904	18,258	18,618	18,984	19,219	19,599	19,986	20,380	20,780	0
PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		9,224	9,224	9,224	9,224	9,224	0	0	0	0	0	0
Debt Coverage Ratio		1.903	1.941	1.979	2.018	2.058	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	1.800											
Minimum Ratio	1.561											
Loan #2												
Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?												
Available Cash: Op Income & PTC, if m(		8,332	8,680	9,034	9,394	9,760	19,219	19,599	19,986	20,380	20,780	0
Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	1											
	ok											
1 Escalating Rate (enter data on right; (calc'd rate in line 158; (selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2 Customized Absolute		7,026	0	0	0	0	0	0	0	0	0	0
	$/kWh											
Active Credit:	$thous	0	0	0	0	0	0	0	0	0	0	0

Graph Points

100 MW IPP - 33.8 cf, Class 4, w/ PTC **09/14/06** **6:51 PM**

		1	2	3	4	5	6	7	8	9	10
	296,088,000 kWh/year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Cost Components in nominal US cents/kWh (money of the year)										
	Revenues	6.747	6.881	7.017	7.157	7.299	7.444	7.592	7.743	7.897	8.054
1	Operations & Maintenance	0.698	0.716	0.733	0.752	0.771	0.790	0.810	0.830	0.851	0.872
2	Royalties, Reserve Deposits	0.113	0.115	0.118	0.121	0.124	0.127	0.131	0.134	0.137	0.141
3	Property Tax	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446
4	Insurance and Other	0.626	0.641	0.658	0.674	0.691	0.708	0.726	0.744	0.763	0.782
5	Interest (Loan #1)	1.986	1.907	1.823	1.732	1.635	1.532	1.421	1.302	1.175	1.039
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	1.129	1.208	1.293	1.383	1.480	1.584	1.695	1.813	1.940	2.076
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	(2.541)	(4.518)	(2.162)	(0.715)	(0.635)	0.494	1.609	1.700	1.795	1.895
10	Production Tax Credits, REPI	(1.900)	(1.948)	(1.996)	(2.046)	(2.097)	(2.150)	(2.203)	(2.259)	(2.315)	(2.373)
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	1.749	1.847	1.947	2.049	2.152	1.764	0.757	0.775	0.791	0.804
	Energy Revenues (with neg tax added as positive)	6.747	6.881	7.017	7.157	7.299	7.444	7.592	7.743	7.897	8.054
check	Energy Revenues	6.700	6.834	6.971	7.110	7.252	7.397	7.545	7.696	7.850	8.007
	Interest on Reserves	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047
check	Total	6.747	6.881	7.017	7.157	7.299	7.444	7.592	7.743	7.897	8.054

Graph Points		100 MW IPP - 33.8 cf, Class 4, w/ PTC								09/14/06	6:51 PM
		11	12	13	14	15	16	17	18	19	20	21
296,088,000	kWh/year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cost Components in nominal US cents/kWh (money of the												
Revenues		8.214	8.377	8.544	8.714	8.887	9.017	9.198	9.382	9.569	9.761	0.000
1 Operations & Maintenance		0.894	0.916	0.939	0.962	0.986	1.011	1.036	1.062	1.089	1.116	0.000
2 Royalties, Reserve Deposits		0.144	0.148	0.151	0.155	0.159	0.163	0.167	0.171	0.176	0.180	0.000
3 Property Tax		0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.000
4 Insurance and Other		0.801	0.821	0.842	0.863	0.884	0.906	0.929	0.952	0.976	1.000	0.000
5 Interest (Loan #1)		0.894	0.739	0.572	0.394	0.204	0.000	0.000	0.000	0.000	0.000	0.000
6 Interest (Loan #2)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7 Principal (Loan #1)		2.221	2.377	2.543	2.721	2.912	0.000	0.000	0.000	0.000	0.000	0.000
8 Principal (Loan #2)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9 Income Tax (benefits rec'd)		1.999	2.108	2.222	2.342	2.468	2.596	2.648	2.700	2.753	2.807	0.000
10 Production Tax Credits, REPI		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11 Cash from Financ'g, Reserves		0.000	0.000	0.000	0.000	1.560	0.000	0.000	0.000	0.000	0.000	0.000
12 After-Tax Cash - Tax Savings		0.815	0.824	0.829	0.830	(0.732)	3.895	3.972	4.050	4.130	4.211	0.000
Energy Revenues (with neg tax added as positive)		8.214	8.377	8.544	8.714	8.887	9.017	9.198	9.382	9.569	9.761	0.000
check Energy Revenues		8.167	8.331	8.497	8.667	8.841	9.017	9.198	9.382	9.569	9.761	0.000
Interest on Reserves		0.047	0.047	0.047	0.047	0.047	0.000	0.000	0.000	0.000	0.000	0.000
check Total		8.214	8.377	8.544	8.714	8.887	9.017	9.198	9.382	9.569	9.761	0.000


100 MW IPP Wind Plant
with Class 4 Winds (33.8% cap factor)
US cents per kWh (nominal)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
1
3
5
7
9
11
13
15
17
19
21
Years
Operations & Maintenance
Royalties, Reserve Deposits
Property Tax
Insurance and Other
Interest (Loan #1)
Interest (Loan #2)
Principal (Loan #1)
Principal (Loan #2)
Income Tax (benefits rec'd)
Production Tax Credits, REPI
Cash from Financ'g, Reserves
After-Tax Cash - Tax Savings

SUMMARY PAGE — 100 MW IPP - 33.8 cf, Class 4, monetized PTC — 09/14/06 — 7:59 PM

File: 0914IPPWind2004_MonetizedPTC.xls

Construction and Development Assumptions and Operating Results

All figures are in thousands of U.S. dollars.

Capital				
Total Project Cost	140,020			
Start Date	2005	at 100% for year 1		
Project Description	100 MW Wind Farm, using Class 4 Winds owned by taxable IPP using limited recourse Project Finance			
Finance				
Debt	84,012	at 7.000%	for 15 years	, customized princ repmt
Secondary Debt	0	at 7.500%	for 18 years	
Equity	56,008			

Total	140,020			
Operations				
Net Rated Capacity	100,000	kW, using	1,500	kW-rated turbines
Actual Hours/Year	8,760	hours/year	67	turbines
Wind Resource	Class 4 Winds			
Net Capacity Factor	33.80%			
Plant Annual Electricity	296,088	thou kWh/year		
Contract Term	20	years		
Operations & Maintenance - fixed	20.67	/kW or	$31,005	/turbine - year
escalating at	2.50%	/year	equiv to 0.698 c/kWh	
Operations & Maintenance - var.	$0.000	/kWh		
escalating at	2.50%	/year		
For land payment, select 1 = percentage revenues, 2 = fixed rent			2	ok
Site Owner Royalty *not used*	0.00%	of revenues		
Site Owner Land Rent *used*	$333.33	thous/year		
escalating at	2.50%	/year	equiv to 0.113 c/kWh	
Property Tax	1.000%	of depreciable base		
escalating at	0.00%	/year		
where base depreciates	0.00%	/year, till hits	0.0%	
Insurance	1.025%	of depreciable base, esc. at	2.50%	/year
Major Maintenance & Overhauls	$500.00	thous/year or	$7,500	/turbine - year
escalating at	2.50%	/year	equiv to 0.169 c/kWh	
			--	
Inflation	2.50%	/year		
Interest Earned on Reserves	3.00%	/year; Interest on Work. Cap	0.50%	/year

Capital Cost per kW installed capacity		1,400	[140020 / 100]	
Cost per Annual kWh		$0.47	[140020 / 296088]	
	--			
	--			
	--			
RETURNS				
using a discount rate of		10.00%		
1 Pre-tax Unleveraged IRR		5.937%	over 20 years	
Net Present Value		(35,604)	using 10%	
Payback		13	years	
2 After-tax Leveraged IRR		20.072%	over 20 years	Target 17%
Net Present Value		23,554	using 10%	
Payback		4	years	
2a Cash-on-Cash Return, excluding PTC		10.655%	average	
(before-tax cash on equity, non-discounted)		1.111%	minimum	
COST OF UTILITY ENERGY	+---- -->	$0.0530	/kWh - first year	
in currency of 2005	+---- -->	$0.0611	/kWh - nominal levelized	
	+---- -->	$0.0498	/kWh - constant$ levelized	
in currency of the year	+---- -->	$0.0500	/kWh - year 21	
in currency of 2004	+---- -->	$0.0596	/kWh - nominal levelized	
	+---- -->	$0.0486	/kWh - constant$ levelized	
using a discount rate of		8.50%	nominal	
		5.85%	constant (with no inflation)	
DEBT COVERAGE	*** PTC is monetized to cover debt paymer			Min Target
Senior Debt Coverage ratio:		1.846	average	1.80 times
		1.656	minimum	1.50 times
Secondary Debt Coverage ratio:		--	average	
--		--	minimum	
Equipment Overhaul Reserve & Drawdown?	no, not undertaken		ok	
Every 10 years, at 0 %, 0%, 0% and 0% of plant cost.				

01/21/2005 note: This Excel spreadsheet model shows cash flow financials for wind energy projects. Enter data in cells with blue lettering as: pg 1: project cost & performance;
pg 2 (Sources): capital costs & selected financial incl'g Revenues; pg 5 (Cash Flow): COE disc rate; pg 7 (Debt): PTC details;
pg 9 (Work Sheet #1): depreciation; pg 11 (Work Sheet #2): senior debt; pg 13 (Work Sheet #3): secondary debt.
By trial and error, a user seeks low COE, an attractive equity return, and good debt coverage, which results are summarized on page 1.

This particular Project is 100 MW, using Class 4 Winds winds with a 33.8% capacity factor. Contract term is 20 years.
Capital Cost is $1260 /kW. O&M is $20.67 /kW and $0 /kWh and $500 thousand per year.

This Project TAKES the 10-year Section 45 Production Tax Credit.
Financing is 60% senior debt at 7% for 15 years and 0% secondary debt and 40% equity.
Sales Tax is $ 0 thousands. Property tax is 1 % of depreciable base, escalating at inflation, but with base depreciating at 0% per year till hits 0%.

Sources and Uses of Funds

100 MW IPP - 33.8 cf, Class 4, monetized PTC **09/14/06** **7:59 PM**

Uses of Funds

in thousands of mixed-year dollars

	Rotor Assembly		16,502		
	Drive Train & Nacelle		37,518		
	Controls, Safety System		667		
	Tower		6,733		
	Market Adjustment		20,000		
	Foundations, Transport, Roads		11,896		
	Assembly, Interconnect, Permits, Engr		13,998		
	Permit/Environmental Adjustment		1,886		
	Manufacturing Uncertainty		10,800		
6,000	Construction Contingency		6,000		
	Home Office Overhead		0		--
	Total	1,260 /kW		126,000	*
	Sales Tax	0		0	*
	Construction Financing	6,000		6,000	*
	(estimated as $120 mil * 10% * 12 mos * 50% for level draw)				
	Construction Insur.			0	*
	Land			0	
	Initial Working Capital: First Year			0	
	Debt Financing Fees	1,680		1,700	--
	(Debt Closing [lawyers,accountants], Commitment Fee; all amortized over the life of the debt)				
	Equity Financing Fees	1,680		1,700	--
	(Tax Advice, Equity Organizational Costs, etc.; part amortized in 1 year, part in 5 years, part excluded)				--
	Debt Service Reserve Fund	4,612		4,620	--
	Working Capital, Operating Reserve	517		0	
	Equipment Repair Reserve Initial Pmt			0	

				140,020	

Misc.

Start Year	2005
Year 1 Calendar Fraction	100.00%
Factor w/ 2 debt pmts/yr	100.00%

Depreciation Rate #1 20%, 32%, 19.2%, 11.52%, 11.52%, 5.76%, 0%

Depreciation Rate #2 5%, 9.5%, 8.55%, 7.7%, 6.93%, 6.23%, 5.9%
5.9%, 5.91%, 5.9%, 5.91%, 5.9%, 5.91%, 5.9%
5.91%, 2.95%, 0%, 0%, 0%, 0%, 0%

Equity Amortization: 40% @ 5 years, 40% @ 1 year, and 20% @ no write-off

Sources of Funds

60.00%	Debt	84,012	at 7.000%	for 15 years	customized principal repayment
0.00%	Second Loan	0	at 7.500%	for 18 years	level mortgage
40.00%	Equity	56,008			
----------		----------			
100.00%		140,020			

Customized debt repayment is 4%, 4%, 5%, 6%, 6%,
7%, 8%, 9%, 10%, 10% and 6%, 7%, 6%, 6%, 6%,
0%, 0%, 0%, 0%, 0% and 0%, 0%, 0%, 0%, 0%,

Taxes

Marginal Tax Rate:	Federal	35.00%	corporate federal rate is 35%,
	State	7.69%	corporate "average" state is 7.69%,
	Combined	40.00%	
Investment Tax Credit		0.00%	

Depreciation

Select 3, 5, 7, 10, 15, or 20 years; using macrs deprec.

Depreciation Class Life #1	5	years; Percent at Life #1	100.00%	ok
Depreciation Class Life #2	15	years; Percent at Life #2	0.00%	ok
Amortization for Equity Finc'g Fees	40.00%	40.00%	20.00%	(See B207 on Sheet2.)

Tax Treatment

Sum of Depreciable Items		132,000	including sales tax		
Primary System Depreciable Base			132,000	5	years
less Tax Credit Adjustmt	50.00%	0			
Primary System Depreciable Base		132,000			
Other Depreciable Base			0	15	years
Amortization over Sr Debt's Life			1,700	15	years
Amortization over Second Debt's Life			0	18	years
5 years' Amortization			680		
1 years' Amortization			680		
No Write-Off			340		
Land			0		
First Year Start-Up (expensed in yr 1)			0		
Reserve Funds			4,620		

			140,020	ok	

Revenues

Energy Pmt	$0.0530	/kWh at	2.00%	/year beginning in year	1
Energy Pmt	$0.0500	/kWh at	2.00%	/year beginning in year	21
Capacity Pmt	$0.00	/kWh at	1.00%	/year	

Earnings — **100 MW IPP - 33.8 cf, Class 4, monetized PTC** — **09/14/06** **7:59 PM**

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Revenues											
	Energy Payment		15,693	16,007	16,327	16,653	16,986	17,326	17,672	18,026	18,386	18,754
	Capacity Payment		0	0	0	0	0	0	0	0	0	0
	Interest on Reserves		139	139	139	139	139	139	139	139	139	139
	Total Revenues		15,831	16,145	16,465	16,792	17,125	17,465	17,811	18,165	18,525	18,893
	Operating Costs											
	Operations & Maintenance - fixed		2,067	2,119	2,172	2,226	2,282	2,339	2,397	2,457	2,518	2,581
	Operations & Maintenance - var.		0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent		333	342	350	359	368	377	387	396	406	416
	Property Tax		1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320
	Insurance		1,353	1,387	1,421	1,457	1,493	1,531	1,569	1,608	1,648	1,690
	Major Maintenance & Overhauls		500	513	525	538	552	566	580	594	609	624
	Total Operating Costs		5,573	5,680	5,789	5,900	6,015	6,132	6,253	6,376	6,502	6,632
	Operating Income		10,258	10,465	10,677	10,891	11,110	11,332	11,559	11,789	12,023	12,261
	Other Expenses											
	Interest on Loan #1		5,881	5,646	5,410	5,116	4,763	4,411	3,999	3,529	2,999	2,411
	Interest on Loan #2		0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee		0	0	0	0	0	0	0	0	0	0
	Depreciation		26,400	42,240	25,344	15,206	15,206	7,603	0	0	0	0
	Repair Depreciation		0	0	0	0	0	0	0	0	0	0
	Amortization		929	249	249	249	249	113	113	113	113	113
	Total Other Expenses		33,210	48,135	31,004	20,572	20,219	12,127	4,112	3,642	3,113	2,524
	Before-Tax Profits		(22,952)	(37,669)	(20,327)	(9,681)	(9,109)	(795)	7,446	8,147	8,910	9,736
40.00%	Income Tax Paid (Benefit Rec'd)		(9,181)	(15,068)	(8,131)	(3,872)	(3,644)	(318)	2,978	3,259	3,564	3,895
	Investment Tax Credit Received		0	0								
	Production Tax Credits Received		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
	After-Tax Profits		(8,146)	(16,835)	(6,286)	250	744	5,888	10,992	11,575	12,200	12,868

Earnings 100 MW IPP - 33.8 cf, Class 4, monetized PTC 09/14/06 7:59 PM

All figures in $thousands.

		11	12	13	14	15	16	17	18	19	20	21
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Revenues											
	Energy Payment	19,129	19,512	19,902	20,300	20,706	21,120	21,543	21,974	22,413	22,861	0
	Capacity Payment	0	0	0	0	0	0	0	0	0	0	0
	Interest on Reserves	139	139	139	139	139	0	0	0	0	0	0
	Total Revenues	19,268	19,650	20,041	20,439	20,845	21,120	21,543	21,974	22,413	22,861	0
	Operating Costs											
	Operations & Maintenance - fixed	2,646	2,712	2,780	2,849	2,921	2,994	3,068	3,145	3,224	3,304	0
	Operations & Maintenance - var.	0	0	0	0	0	0	0	0	0	0	0
	Site Owner Land Rent	427	437	448	460	471	483	495	507	520	533	0
	Property Tax	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320	0
	Insurance	1,732	1,775	1,820	1,865	1,912	1,960	2,009	2,059	2,110	2,163	0
	Major Maintenance & Overhauls	640	656	672	689	706	724	742	761	780	799	0
	Total Operating Costs	6,765	6,901	7,040	7,183	7,330	7,480	7,634	7,792	7,954	8,120	0
	Operating Income	12,503	12,750	13,000	13,255	13,515	13,640	13,909	14,182	14,459	14,742	0
	Other Expenses											
	Interest on Loan #1	1,823	1,470	1,059	706	353	0	0	0	0	0	0
	Interest on Loan #2	0	0	0	0	0	0	0	0	0	0	0
	Loan Guarantee Fee	0	0	0	0	0	0	0	0	0	0	0
	Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Repair Depreciation	0	0	0	0	0	0	0	0	0	0	0
	Amortization	113	113	113	113	113	0	0	0	0	0	0
	Total Other Expenses	1,936	1,584	1,172	819	466	0	0	0	0	0	0
	Before-Tax Profits	10,567	11,166	11,829	12,436	13,049	13,640	13,909	14,182	14,459	14,742	0
40.00%	Income Tax Paid (Benefit Rec'd)	4,227	4,466	4,731	4,975	5,219	5,456	5,563	5,673	5,784	5,897	0
	Investment Tax Credit Received											
	Production Tax Credits Received	0	0	0	0	0	0	0	0	0	0	0
	After-Tax Profits	6,340	6,700	7,097	7,462	7,829	8,184	8,345	8,509	8,676	8,845	0

Cash Flow & COE — **100 MW IPP - 33.8 cf, Class 4, monetized PTC** — **09/14/06** **7:59 PM**

All figures in $thousands.	0 2004	1 2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012	9 2013	10 2014
Before-Tax Profits		(22,952)	(37,669)	(20,327)	(9,681)	(9,109)	(795)	7,446	8,147	8,910	9,736
Add Back:											
Year 1 Cash from Financing		0									
Depreciation & Repair Deprec.		26,400	42,240	25,344	15,206	15,206	7,603	0	0	0	0
Amortization		929	249	249	249	249	113	113	113	113	113
Released from Reserve		0	0	0	0	0	0	0	0	0	0
Total Additions		27,329	42,489	25,593	15,456	15,456	7,717	113	113	113	113
Subtract Off:											
Loan #1 Principal		3,360	3,360	4,201	5,041	5,041	5,881	6,721	7,561	8,401	8,401
Loan #2 Principal		0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)		0	0	0	0	0	0	0	0	0	0
Total Subtractions		3,360	3,360	4,201	5,041	5,041	5,881	6,721	7,561	8,401	8,401
Before-Tax Cash		1,017	1,459	1,066	734	1,306	1,041	839	699	622	1,449
Taxes Payable (Benefit Received)		(9,181)	(15,068)	(8,131)	(3,872)	(3,644)	(318)	2,978	3,259	3,564	3,895
Investment Tax Credit		0	0								
Production Tax Credit		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
After-Tax Cash	(56,008)	15,823	22,293	15,107	10,665	11,159	7,724	4,384	4,128	3,913	4,580

After-tax IRR 20.072%
using starting estimate of 12.000% .
Net Present Value 23,554 , using 10.00% as discount rate for developer
Payback 4

	0	1	2	3	4	5	6	7	8	9	10
		1	1	1	1	0	0	0	0	0	0

Cash-on-Cash Return (before-tax cash vs. equity investment, ignoring time value of money [and discount factor] and excluding tax credits, tax losses, tax payments)
Minimum 1.11% <-- -- Reset both as years of project
Average 10.65%

	0	1	2	3	4	5	6	7	8	9	10
Before-Tax Cash and Equity Investmen	(56,008)	1,017	1,459	1,066	734	1,306	1,041	839	699	622	1,449
BT Cash to Equity Investment (not discounted)		1.82%	2.61%	1.90%	1.31%	2.33%	1.86%	1.50%	1.25%	1.11%	2.59%

		1	2	3	4	5	6	7	8	9	10
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Electric Revenues:	Energy	15,693	16,007	16,327	16,653	16,986	17,326	17,672	18,026	18,386	18,754
	Capacity	0	0	0	0	0	0	0	0	0	0
Total (thousands)		15,693	16,007	16,327	16,653	16,986	17,326	17,672	18,026	18,386	18,754

Net Present Value 171,249 , using 8.500% <--- SET THIS! Before-tax rate, from utility's cost of capital
Current $ Levelized 18,096 as Rate * NPV/(1-(1+Rate)^(-n)) (e.g., 5.50% for tax-free coop; 8.5% for IOU) *

lev COE/kWh $0.0611 in nominal terms of 2005
lev COE/kWh $0.0596 in nominal terms of 2004

04/30/01 note: NPV boosts year 1 to 100% and cuts any N+1 last year to zero.

1st-yr Cost $0.0530
Constant $ NPV 171,249 , as nominal
Constant $ levelized 14,753 , using 5.854% = (1 + 0.085)/(1 + 0.025) - 1
lev COE/kWh $0.0498 in constant terms of 2005
lev COE/kWh $0.0486 in constant terms of 2004

Cash Flow & COE — **100 MW IPP - 33.8 cf, Class 4, monetized PTC** — **09/14/06** — **7:59 PM**

All figures in $thousands.	11 2015	12 2016	13 2017	14 2018	15 2019	16 2020	17 2021	18 2022	19 2023	20 2024	21 2025
Before-Tax Profits	10,567	11,166	11,829	12,436	13,049	13,640	13,909	14,182	14,459	14,742	0
Add Back:											
Year 1 Cash from Financing											
Depreciation & Repair Deprec.	0	0	0	0	0	0	0	0	0	0	0
Amortization	113	113	113	113	113	0	0	0	0	0	0
Released from Reserve	0	0	0	0	4,620	0	0	0	0	0	0
Total Additions	113	113	113	113	4,733	0	0	0	0	0	0
Subtract Off:											
Loan #1 Principal	5,041	5,881	5,041	5,041	5,041	0	0	0	0	0	0
Loan #2 Principal	0	0	0	0	0	0	0	0	0	0	0
Other (e.g., Reserve Deposit)	0	0	0	0	0	0	0	0	0	0	0
Total Subtractions	5,041	5,881	5,041	5,041	5,041	0	0	0	0	0	0
Before-Tax Cash	5,639	5,399	6,901	7,509	12,741	13,640	13,909	14,182	14,459	14,742	0
Taxes Payable (Benefit Received)	4,227	4,466	4,731	4,975	5,219	5,456	5,563	5,673	5,784	5,897	0
Investment Tax Credit											
Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0
After-Tax Cash	1,413	932	2,170	2,534	7,522	8,184	8,345	8,509	8,676	8,845	0
	0	0	0	0	0	0	0	0	0	0	0
:t life varies.											
Before-Tax Cash and Equity Investmen	5,639	5,399	6,901	7,509	12,741	13,640	13,909	14,182	14,459	14,742	0
BT Cash to Equity Investment (not disc	10.07%	9.64%	12.32%	13.41%	22.75%	24.35%	24.83%	25.32%	25.82%	26.32%	0.00%

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
COST OF ENERGY	Cal fraction	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%
Electric Revenues:	Energy	19,129	19,512	19,902	20,300	20,706	21,120	21,543	21,974	22,413	22,861	0
	Capacity	0	0	0	0	0	0	0	0	0	0	0
Total (thousands)		19,129	19,512	19,902	20,300	20,706	21,120	21,543	21,974	22,413	22,861	0

*To figure Discount rate:

Utility debt	50.00%	6.50%
preferred	5.00%	6.30%
common	45.00%	11.00%

8.52% weighted average cost of capital

Debt Redemption & PTC

100 MW IPP - 33.8 cf, Class 4, monetized PTC 09/14/06 7:59 PM

All figures in $thousands.

		0	1	2	3	4	5	6	7	8	9	10
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Loan #1		84,012	at 7.000%	for 15 years	customized principal repayment -- with ONE payment/year							
Beginning Balance			84,012	80,652	77,291	73,090	68,050	63,009	57,128	50,407	42,846	34,445
Interest			5,881	5,646	5,410	5,116	4,763	4,411	3,999	3,529	2,999	2,411
Loan Guarantee Fees			0	0	0	0	0	0	0	0	0	0
Principal			3,360	3,360	4,201	5,041	5,041	5,881	6,721	7,561	8,401	8,401
Total			9,241	9,006	9,611	10,157	9,804	10,291	10,720	11,090	11,400	10,812
Available Cash: Operating Income			10,258	10,465	10,677	10,891	11,110	11,332	11,559	11,789	12,023	12,261
PTC monetization, if any			5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
Total Debt Service			9,241	9,006	9,611	10,157	9,804	10,291	10,720	11,090	11,400	10,812
Debt Coverage Ratio			1.719	1.802	1.726	1.669	1.767	1.720	1.687	1.666	1.656	1.784
Average Ratio	1.846		not counting last partial year									
Minimum Ratio	1.656											
Loan #2		0	at 7.500%	for 18 years	level mortgage -- with ONE payment/year							
Beginning Balance			0	0	0	0	0	0	0	0	0	0
Interest			0	0	0	0	0	0	0	0	0	0
Principal			0	0	0	0	0	0	0	0	0	0
Total			0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?	yes		, where yes means pay senior debt first or no is pay both loans together.									
Available Cash: Op Income & PTC, if monetized			6,642	7,226	6,976	6,793	7,515	7,406	7,363	7,386	7,477	8,474
Total Debt Service			0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											

Prod'n Tax Credit	1		Select 1 = escalating rate by formula or 2 = customized rate or 3 = TURNED OFF for no credit at all.							PTC expires 12/31/2007, unless extended.		
	ok											
1 Escalating Rate		{	Starting Credit	$0.019 /kWh;	Start Year		1		yr 1 fraction	1.000 }		
(enter data on right;		{	Escal Rate	2.500% year;	Last Year		10			}		
(calc'd rate in line 158;		{								}		
(selected rate in line 163.)		{	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026
2 Customized Absolute			0	5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854
	$/kWh		0.01900	0.01948	0.01996	0.02046	0.02097	0.02150	0.02203	0.02259	0.02315	0.02373
Active Credit:	$thous		5,626	5,766	5,910	6,058	6,210	6,365	6,524	6,687	6,854	7,026

Debt Redemption & PTC — **100 MW IPP - 33.8 cf, Class 4, monetized PTC** — **09/14/06** **7:59 PM**

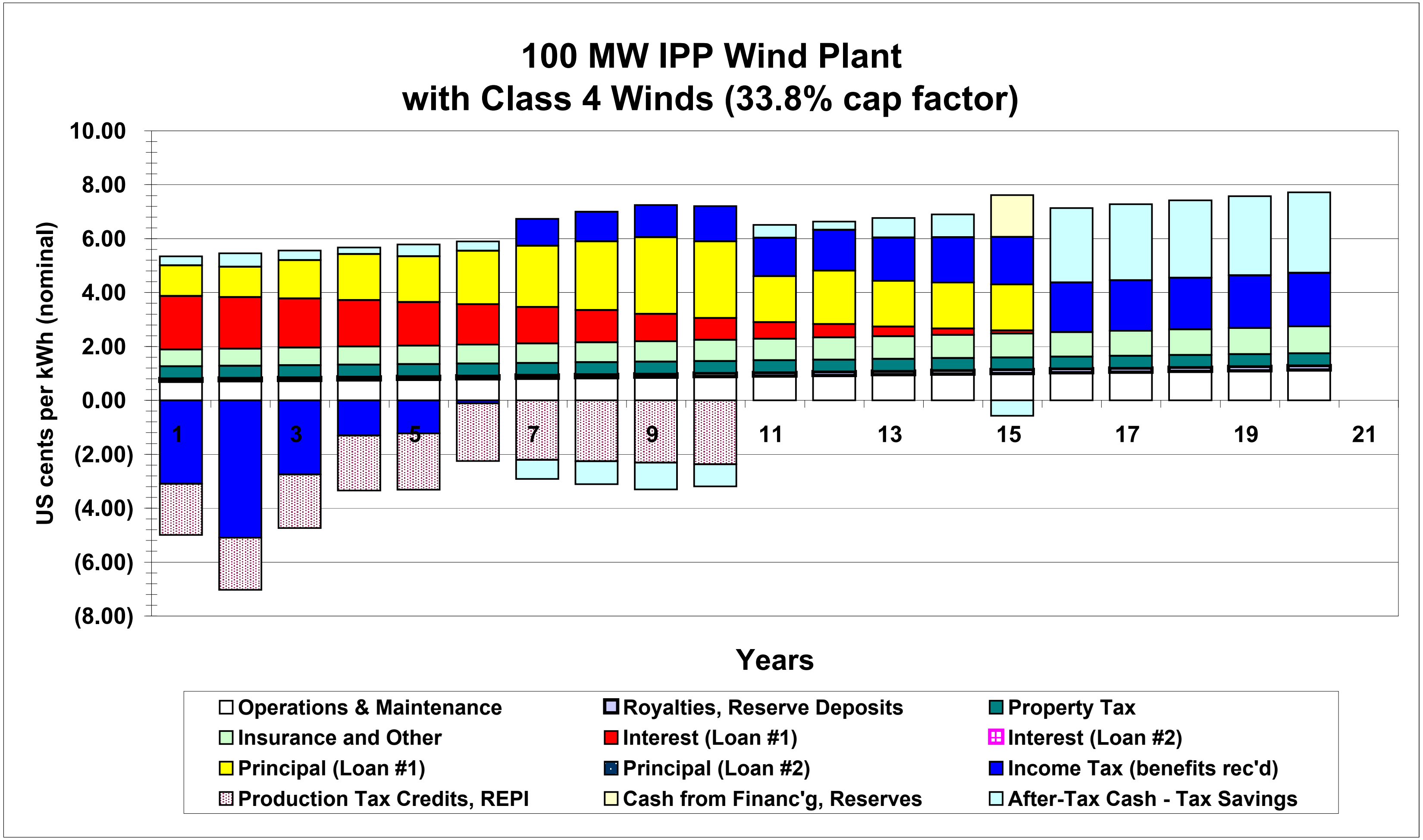
All figures in $thousands.

		11 2015	12 2016	13 2017	14 2018	15 2019	16 2020	17 2021	18 2022	19 2023	20 2024	21 2025
Loan #1												
Beginning Balance		26,044	21,003	15,122	10,081	5,041	(0)	(0)	(0)	(0)	(0)	(0)
Interest		1,823	1,470	1,059	706	353	0	0	0	0	0	0
Loan Guarantee Fees		0	0	0	0	0	0	0	0	0	0	0
Principal		5,041	5,881	5,041	5,041	5,041	0	0	0	0	0	0
Total		6,864	7,351	6,099	5,746	5,394	0	0	0	0	0	0
Available Cash: Operating Income		12,503	12,750	13,000	13,255	13,515	13,640	13,909	14,182	14,459	14,742	0
PTC monetization, if any		0	0	0	0	0	0	0	0	0	0	0
Total Debt Service		6,864	7,351	6,099	5,746	5,394	0	0	0	0	0	0
Debt Coverage Ratio		1.822	1.734	2.131	2.307	2.506	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	1.846											
Minimum Ratio	1.656											
Loan #2												
Beginning Balance		0	0	0	0	0	0	0	0	0	0	0
Interest		0	0	0	0	0	0	0	0	0	0	0
Principal		0	0	0	0	0	0	0	0	0	0	0
Total		0	0	0	0	0	0	0	0	0	0	0
Is second loan subordinate?												
Available Cash: Op Income & PTC, if mo		5,639	5,399	6,901	7,509	8,121	13,640	13,909	14,182	14,459	14,742	0
Total Debt Service		0	0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Average Ratio	0.000											
Minimum Ratio	0.000											
Times Interest Earned		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Minimum Ratio	0.000											
Prod'n Tax Credit	1 ok											
1 Escalating Rate (enter data on right; (calc'd rate in line 158; (selected rate in line 163.)		0	0	0	0	0	0	0	0	0	0	0
2 Customized Absolute		7,026	0	0	0	0	0	0	0	0	0	0
Active Credit:	$/kWh $thous	0	0	0	0	0	0	0	0	0	0	0

Graph Points	100 MW IPP - 33.8 cf, Class 4, monetized PTC							09/14/06	7:59 PM	
	1	2	3	4	5	6	7	8	9	10
296,088,000 kWh/year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Cost Components in nominal US cents/kWh (money of the year)										
Revenues	5.347	5.453	5.561	5.671	5.784	5.898	6.015	6.135	6.257	6.381
1 Operations & Maintenance	0.698	0.716	0.733	0.752	0.771	0.790	0.810	0.830	0.851	0.872
2 Royalties, Reserve Deposits	0.113	0.115	0.118	0.121	0.124	0.127	0.131	0.134	0.137	0.141
3 Property Tax	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446
4 Insurance and Other	0.626	0.641	0.658	0.674	0.691	0.708	0.726	0.744	0.763	0.782
5 Interest (Loan #1)	1.986	1.907	1.827	1.728	1.609	1.490	1.351	1.192	1.013	0.814
6 Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7 Principal (Loan #1)	1.135	1.135	1.419	1.702	1.702	1.986	2.270	2.554	2.837	2.837
8 Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9 Income Tax (benefits rec'd)	(3.101)	(5.089)	(2.746)	(1.308)	(1.231)	(0.107)	1.006	1.101	1.204	1.315
10 Production Tax Credits, REPI	(1.900)	(1.948)	(1.996)	(2.046)	(2.097)	(2.150)	(2.203)	(2.259)	(2.315)	(2.373)
11 Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12 After-Tax Cash - Tax Savings	0.343	0.493	0.360	0.248	0.441	0.352	(0.723)	(0.864)	(0.994)	(0.826)
Energy Revenues (with neg tax added as positive)	5.347	5.453	5.561	5.671	5.784	5.898	6.015	6.135	6.257	6.381
check Energy Revenues	5.300	5.406	5.514	5.624	5.737	5.852	5.969	6.088	6.210	6.334
Interest on Reserves	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047	0.047
check Total	5.347	5.453	5.561	5.671	5.784	5.898	6.015	6.135	6.257	6.381

Graph Points 100 MW IPP - 33.8 cf, Class 4, monetized PTC 09/14/06 7:59 PM

		11	12	13	14	15	16	17	18	19	20	21
	296,088,000 kWh/year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Cost Components in nominal US cents/kWh (money of the											
	Revenues	6.507	6.637	6.768	6.903	7.040	7.133	7.276	7.421	7.570	7.721	0.000
1	Operations & Maintenance	0.894	0.916	0.939	0.962	0.986	1.011	1.036	1.062	1.089	1.116	0.000
2	Royalties, Reserve Deposits	0.144	0.148	0.151	0.155	0.159	0.163	0.167	0.171	0.176	0.180	0.000
3	Property Tax	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.446	0.000
4	Insurance and Other	0.801	0.821	0.842	0.863	0.884	0.906	0.929	0.952	0.976	1.000	0.000
5	Interest (Loan #1)	0.616	0.497	0.358	0.238	0.119	0.000	0.000	0.000	0.000	0.000	0.000
6	Interest (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	Principal (Loan #1)	1.702	1.986	1.702	1.702	1.702	0.000	0.000	0.000	0.000	0.000	0.000
8	Principal (Loan #2)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	Income Tax (benefits rec'd)	1.428	1.508	1.598	1.680	1.763	1.843	1.879	1.916	1.953	1.992	0.000
10	Production Tax Credits, REPI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11	Cash from Financ'g, Reserves	0.000	0.000	0.000	0.000	1.560	0.000	0.000	0.000	0.000	0.000	0.000
12	After-Tax Cash - Tax Savings	0.477	0.315	0.733	0.856	(0.580)	2.764	2.818	2.874	2.930	2.987	0.000
	Energy Revenues (with neg tax added as positive)	6.507	6.637	6.768	6.903	7.040	7.133	7.276	7.421	7.570	7.721	0.000
check	Energy Revenues	6.461	6.590	6.722	6.856	6.993	7.133	7.276	7.421	7.570	7.721	0.000
	Interest on Reserves	0.047	0.047	0.047	0.047	0.047	0.000	0.000	0.000	0.000	0.000	0.000
check	Total	6.507	6.637	6.768	6.903	7.040	7.133	7.276	7.421	7.570	7.721	0.000


100 MW IPP Wind Plant
with Class 4 Winds (33.8% cap factor)
10.00
8.00
6.00
4.00
2.00
0.00
(2.00)
(4.00)
(6.00)
(8.00)
US cents per kWh (nominal)
1
3
5
7
9
11
13
15
17
19
21
Years
Operations & Maintenance
Royalties, Reserve Deposits
Property Tax
Insurance and Other
Interest (Loan #1)
Interest (Loan #2)
Principal (Loan #1)
Principal (Loan #2)
Income Tax (benefits rec'd)
Production Tax Credits, REPI
Cash from Financ'g, Reserves
After-Tax Cash - Tax Savings

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This report details the methodology used by the U.S. Department of Energy to calculate levelized cost of wind energy and demonstrates the variation in COE estimates due to different financing assumptions independent of wind generation technology.

15. SUBJECT TERMS
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