RECEIVED

DEC 07 2007

PUBLIC SERVICE
COMMISSION

Kentucky Utilities Company

Financial Statements

(Unaudited)

As of September 30, 2007 and 2006

TABLE OF CONTENTS

Kentucky Utilities Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	September 30, 2007	December 31, 2006
Current assets:		
Cash and cash equivalents	$ 1	$ 6
Restricted cash (Note 6)	40	23
Accounts receivable – less reserves of $2 million	168	123
Accounts receivable from affiliated companies (Note 8)	6	50
Income tax receivable	-	6
Materials and supplies:		
Fuel (predominantly coal)	49	64
Other materials and supplies	34	34
Prepayments and other current assets	4	7
Total current assets	302	313
Other property and investments	28	25
Utility plant:		
At original cost	4,714	4,168
Less: reserve for depreciation	1,604	1,553
Net utility plant	3,110	2,615
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	66	64
Other	111	83
Cash surrender value of key man life insurance	36	35
Other assets	9	8
Total deferred debits and other assets	222	190
Total assets	$ 3,662	$ 3,143

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Nine Months Ended September 30, 2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 130	$ 109
Items not requiring cash currently:		
Depreciation and amortization	89	86
Deferred income taxes	(2)	1
VDT amortization	-	3
Investment tax credit - net	28	-
Other	2	10
Changes in current assets and liabilities:		
Accounts receivable	(1)	35
Materials and supplies	15	(4)
Other current assets	3	(6)
Accounts payable	(26)	25
Accrued income taxes	9	(13)
Other current liabilities	1	13
Pension funding	(13)	-
Fuel adjustment clause receivable, net	(22)	(24)
MISO exit	-	(20)
Other	(4)	(7)
Net cash provided by operating activities	209	208
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(512)	(236)
Change in restricted cash	(17)	7
Net cash used for investing activities	(529)	(229)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Retirement of bonds (Note 6)	(107)	(36)
Proceeds from issuance of affiliated company debt (Note 6)	502	50
Repayment of debt from affiliated company (Note 6)	(216)	(11)
Issuance of pollution control bonds	81	16
Capital contribution	55	-
Net cash provided by financing activities	315	19
CHANGE IN CASH AND CASH EQUIVALENTS	(5)	(2)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	6	7
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 1	$ 5

The accompanying notes are an integral part of these financial statements.

The following regulatory assets and liabilities were included in KU's Balance Sheets:

Kentucky Utilities Company
(unaudited)

(in millions)	September 30, 2007	December 31, 2006
FAC	$ 38	$ 16
ARO	24	22
MISO exit	20	20
ECR	11	10
Unamortized loss on bonds	10	10
Other	8	5
Subtotal	111	83
Pension and postretirement benefits	66	64
Total regulatory assets	$ 177	$ 147
Accumulated cost of removal of utility plant	$304	$ 297
Deferred income taxes – net	29	27
Other	10	6
Total regulatory liabilities	$ 343	$ 330

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset which represents the changes in funded status of the plans. The Company will seek recovery of this asset in future proceedings with the Kentucky and Virginia Commissions. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. KU expects to seek recovery of this asset in future proceedings with the Kentucky and Virginia Commissions. KU currently earns a rate of return on the remaining regulatory assets.

FAC. In December 2006, the Kentucky Commission initiated its periodic two-year review of KU's past operations of the fuel clause and transfer of fuel costs from the FAC to base rates. In March 2007, intervenors representing industrial customers challenged KU's recovery of $5.1 million in aggregate fuel costs KU incurred during a period prior to its exit from the MISO and requested the Kentucky Commission disallow this amount. A public hearing was held in May 2007. Final briefs were filed by the Company and the intervenors in June 2007. In October 2007, the Kentucky Commission issued its Order in this proceeding. The Kentucky Commission findings were that KU incurred no improper fuel cost during the two-year review period and that KU was in compliance with the provisions of Administrative Regulation 807 KAR 5:5056. The Kentucky Commission further approved KU's recommendation for the transfer of fuel cost from the FAC to base rates. In November 2007, the KIUC filed a petition for rehearing, claiming the Kentucky Commission misinterpreted the KIUC's arguments in the proceeding. The Company expects a ruling from the Kentucky Commission by the end of November 2007.

choice for most consumers in the applicable regions of the state. Thereafter, a hybrid model of regulation is expected to apply in Virginia, whereby utility rates would be reviewed every two years and a utility's rate of return on equity shall not be set lower than the average of the rates of return for other regional utilities, with certain caps, floors or adjustments. The legislation is effective in July 2007, and also includes a 10% nonbinding goal for renewable power generation by 2022, as well as incentives for new generation, including renewables. Under the legislation KU retains an existing exemption from customer choice and other restructuring activities as applicable to KU's limited service territory in Virginia. However, KU will be subject to a rate proceeding in the first six months of 2009 based on calendar year 2008 financial data under the hybrid model of regulation. Beginning in 2011, KU will make biennial rate filings with the Virginia Commission.

Ghent FGD Inquiry. In October 2006, the Kentucky Commission commenced an inquiry into elements of KU's planned construction of one of its three new FGDs at the Ghent generating station. The proceeding requested, and KU provided, additional information regarding configuration details, expenditures and the proposed construction sequence applicable to future construction phases of the Ghent FGD project. In January 2007, the Kentucky Commission issued an Order completing its inquiry in the matter and confirming its approval of KU's construction plan. The Order also provided general guidance for jurisdictional utilities regarding applicable information and data requirements for future CCN applications and subsequent proceedings.

Note 3 - Financial Instruments

Interest Rate Swaps (hedging derivatives). KU has used over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature. Management has designated all of the interest rate swaps as hedge instruments. Financial instruments designated as fair value hedges and the underlying hedged items are periodically marked to market with the resulting net gains and losses recorded directly into net income. Upon termination of any fair value hedge, the resulting gain or loss is recorded into net income. Financial instruments designated as cash flow hedges have resulting gains and losses recorded within stockholders' equity.

KU was party to an interest rate swap agreement with a notional amount of $53 million as of December 31, 2006. The interest rate swap was terminated in February 2007, when the underlying debt was defeased. Under this swap agreement, KU paid variable rates based on LIBOR averaging 7.44% and received fixed rates averaging 7.92% in 2007, prior to the termination of the swap. The swap agreement in effect at December 31, 2006, had been designated as a fair value hedge. The fair value designation was assigned because the underlying fixed rate debt had a firm future commitment. For the nine months ended September 30, 2006, the effect of marking these financial instruments and the underlying debt to market resulted in pre-tax gains of less than $1 million recorded in interest expense. There was no activity related to the swap in the third quarter of 2007, due to its termination in February 2007.

Interest rate swaps hedge interest rate risk on the underlying debt. Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, in addition to swaps being marked to market, the item being hedged must also be marked to market. Consequently for the year ended December 31, 2006, KU's debt reflects a mark-to-market adjustment of less than $1 million.

anticipates making further voluntary contributions in 2007 to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the postretirement medical account under the pension plan up to the maximum amount allowed by law.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including KU, will calculate its separate income tax for the tax period. The resulting separate-return tax cost or benefit will be paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. With few exceptions, KU is no longer subject to U.S. federal, state or non-U.S. income tax examinations by tax authorities for years before 2004. Statutes of limitations related to the 2004 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to the actual calendar year applicable to the return and ends 90 days after the return is filed.

KU adopted the provisions of FIN 48 effective January 1, 2007. At the date of adopting FIN 48, KU had $2 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the entire $2 million of unrecognized tax benefits would reduce the effective tax rate.

Included in other liabilities at September 30, 2007, is less than $1 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Furthermore, possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total $1 million. The estimated amount of the change in uncertain tax position is based on the expiration of statutes during 2007.

KU, upon adoption of FIN 48, adopted a new financial statement classification for interest and penalties. Prior to the adoption of FIN 48, KU recorded interest and penalties for income taxes on the income statement in income tax expense and in the taxes accrued balance sheet account, net of tax. Upon adoption of FIN 48, interest and penalties are recorded as operating expenses on the income statement and accrued expenses in the balance sheet, on a pre-tax basis. The interest accrued is based on federal and state large corporate underpayment interest rates.

The amount KU recognized as interest accrued related to unrecognized tax benefits in interest expense in operating expenses was less than $1 million at both September 30, 2007 and December 31, 2006. No penalties were accrued by KU upon adoption of FIN 48 or through September 30, 2007.

In June 2006, KU and LG&E filed a joint application with the DOE requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. An additional IRS certification required to obtain the investment tax credit was received in August 2007. KU's portion of the tax credit will be approximately $101 million over the construction period of TC2 and will be amortized to income over the life of the related property. In the third quarter of 2007, based on eligible construction expenditures incurred in 2007, KU recorded $10 million of federal investment tax credit. The credit recorded decreased current federal income taxes by $10 million, during the three months ended September 30, 2007, and $30 million for the nine months ended September 30, 2007.

E.ON U.S. maintains a revolving credit facility totaling $150 million and $200 million at September 30, 2007 and December 31, 2006, respectively, with an affiliated company, E.ON North America, Inc., to ensure funding availability for the money pool. The balance is as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2007	$150	$122	$28	5.45%
December 31, 2006	$200	$102	$98	5.49%

Redemptions of long-term debt year-to-date through September 30, 2007, are summarized below:

Year	Description	Principal Amount (in millions)	Rate	Secured/ Unsecured	Maturity
2007	Pollution control bonds	$54	Variable	Secured	2024
2007	First mortgage bonds	$53	7.92%	Secured	2007

Issuances of long-term debt year-to-date through September 30, 2007, are summarized below:

Year	Description	Principal Amount (in millions)	Rate	Secured/ Unsecured	Maturity
2007	Pollution control bonds	$ 54	Variable	Unsecured	2034
2007	Pollution control bonds	$ 18	Variable	Unsecured	2026
2007	Pollution control bonds	$ 9	Variable	Unsecured	2037
2007	Due to Fidelia	$ 53	5.69%	Unsecured	2022
2007	Due to Fidelia	$ 75	5.86%	Unsecured	2037
2007	Due to Fidelia	$ 50	5.98%	Unsecured	2017
2007	Due to Fidelia	$100	5.96%	Unsecured	2028

KU no longer has any secured debt and is no longer subject to periodic reporting under the Securities Exchange Act of 1934.

In October 2007, KU entered into a long-term borrowing arrangement with Fidelia in principal amount of $70 million.

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in KU's Annual Report for the year ended December 31, 2006 (including in Notes 2 and 9 to the financial statements of KU contained therein). See the above-referenced notes in KU's Annual Report regarding such commitments or contingencies.

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop an SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85 percent from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, in 2002, Kentucky amended its SIP to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which requires additional SO_2 emission reductions of 70 percent and NOx emission reductions of 65 percent from 2003 levels. The CAIR provides for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. The final rule is currently under challenge in a number of federal court proceedings. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local non-attainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. KU's weighted-average company-wide emission rate for SO_2 in the third quarter of 2007 was approximately 1.21 lbs./MMBtu of heat input, with every generating unit below its emission limit established by the Kentucky Division for Air Quality.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provides for reductions of 70 percent from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets will be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. The final rule is also currently under challenge in the federal courts. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAMR. In addition, in 2005 and 2006, state and local air agencies in Kentucky have proposed or adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants. To the extent those rules are final, they are not expected to have a material impact on KU's power plant operations.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. During 2006, KU provided data responses to the EPA with respect to the allegations in the NOVs. In March 2007, the Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint seeks civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, a July 2009 date for trial on the merits was scheduled. The parties continue periodic settlement discussions. KU cannot determine the overall outcome or potential effects of these matters, including whether substantial fines, penalties or remedial construction may result.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain construction and maintenance activities at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. The Companies are complying with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September, 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July 2007 at Units 1 and 3 of KU's Ghent generating station. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial construction may result.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and ongoing claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of KU.

Note 8 - Related Party Transactions

KU and other subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail customers and to satisfy off-system sales. These sales and purchases are included in the statements of

In September 2007, KU received a capital contribution from its common shareholder, E.ON U.S. in the amount of $55 million.

Note 9 - Subsequent Events

On October 25, 2007, KU entered into a long-term borrowing agreement with Fidelia with a principal amount of $70 million, interest rate of 5.71% and a maturity date of October, 25, 2019.

Louisville Gas and Electric Company

Financial Statements
(Unaudited)

As of September 30, 2007 and 2006

TABLE OF CONTENTS

Louisville Gas and Electric Company
Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Balance at beginning of period	$ 625	$ 609	$ 639	$ 621
Net income	45	40	101	90
Preferred stock buyback	-	-	(4)	-
Subtotal	670	649	736	711
Cash dividends declared on stock:				
Cumulative preferred	-	-	1	2
Common	-	35	65	95
Subtotal	-	35	66	97
Balance at end of period	$ 670	$ 614	$ 670	$ 614

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	September 30, 2007	December 31, 2006
Current liabilities:		
Current portion of long-term debt	$ 120	$ 248
Notes payable to affiliated companies (Note 6 and Note 9)	106	68
Accounts payable	89	103
Accounts payable to affiliated companies (Note 9)	36	55
Customer deposits	19	18
Other current liabilities	39	40
Total current liabilities	409	532
Long-term debt:		
Long-term debt (Note 6)	455	328
Long-term debt to affiliated company (Note 6 and Note 9)	363	225
Mandatorily redeemable preferred stock	-	19
Total long-term debt	818	572
Deferred credits and other liabilities:		
Accumulated deferred income taxes	341	333
Accumulated provision for pensions and related benefits	95	149
Investment tax credit	47	41
Asset retirement obligation	29	28
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	239	232
Deferred income taxes – net and other	70	89
Other liabilities	43	44
Total deferred credits and other liabilities	864	916
Cumulative preferred stock	-	70
Common equity:		
Common stock, without par value –		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	40	40
Accumulated comprehensive loss	(8)	(9)
Retained earnings	670	639
Total common equity	1,126	1,094
Total liabilities and equity	$ 3,217	$ 3,184

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Comprehensive Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Net income	$ 45	$ 40	$ 101	$ 90
Gain (loss) on derivative instruments and hedging activities – net of tax benefit (expense) of $3 million, $4 million, $(1) million and $(1) million, respectively (Note 3)	(4)	(6)	1	2
Comprehensive income, net of tax	(4)	(6)	1	2
Comprehensive income	$ 41	$ 34	$ 102	$ 92

The accompanying notes are an integral part of these financial statements.

The following regulatory assets and liabilities were included in LG&E's Balance Sheets:

Louisville Gas and Electric Company
(unaudited)

(in millions)	September 30, 2007	December 31, 2006
ARO	$ 24	$ 22
Unamortized loss on bonds	19	20
Gas supply adjustments	16	21
FAC	14	4
MISO exit	13	13
ECR	4	9
Other	9	4
Subtotal	99	93
Pension and postretirement benefits	126	126
Total regulatory assets	$ 225	$ 219
Accumulated cost of removal of utility plant	$ 239	$ 232
Deferred income taxes – net	50	54
Gas supply adjustments	12	31
Other	8	4
Total regulatory liabilities	$ 309	$ 321

LG&E does not currently earn a rate of return on the regulatory assets associated with the gas supply cost and gas performance-based ratemaking adjustments (both made through the Gas Supply Clause) and FAC; both the Gas Supply Clause and the FAC are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset which represents the changes in funded status of the plans. The Company will seek recovery of this asset in future proceedings with the Kentucky Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. LG&E expects to seek recovery of this asset in future proceedings with the Kentucky Commission. LG&E currently earns a rate of return on the remaining regulatory assets.

FAC. In December 2006, the Kentucky Commission initiated its periodic two-year review of LG&E's past operations of the fuel clause and transfer of fuel costs from the FAC to base rates. In March 2007, intervenors representing industrial customers challenged LG&E's recovery of $0.5 million in aggregate fuel costs LG&E incurred during a period prior to its exit from the MISO and requested the Kentucky Commission disallow this amount. A public hearing was held in May 2007. Final briefs were filed by the Company and the intervenors in June 2007. In October 2007, the Kentucky Commission issued its Order in this proceeding. The Kentucky Commission findings were that LG&E incurred no improper fuel cost during the two-year review period and that LG&E was in compliance with the provisions of Administrative Regulation 807 KAR 5:5056. The Kentucky Commission further approved LG&E's recommendation for the transfer of fuel cost from the FAC to base rates. In November 2007, the KIUC filed a petition for rehearing, claiming the Kentucky Commission misinterpreted the KIUC's arguments in the proceeding. The Company expects a ruling from the Kentucky Commission by the end of November 2007.

retail gas activities. This corrective event places these activities in compliance for future periods. In August 2007, the FERC advised LG&E that it had concluded its investigation related to prior periods and had closed the matter with no further actions.

Note 3 - Financial Instruments

Interest Rate Swaps (hedging derivatives). LG&E uses over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. Pursuant to Company policy, use of these financial instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature. Management has designated all of the interest rate swaps as hedge instruments. Financial instruments designated as cash flow hedges have resulting gains and losses recorded within other comprehensive income and stockholders' equity. Financial instruments designated as fair value hedges and the underlying hedged items are periodically marked to market with the resulting net gains and losses recorded directly into net income. Upon termination of any fair value hedge, the resulting gain or loss is recorded into net income.

LG&E was party to various interest rate swap agreements with aggregate notional amounts of $211 million as of September 30, 2007 and December 31, 2006. Under these swap agreements, LG&E paid fixed rates averaging 4.38% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 3.87% at September 30, 2007. The swap agreements in effect at September 30, 2007, have been designated as cash flow hedges and mature on dates ranging from 2020 to 2033. The cash flow designation was assigned because the underlying variable rate debt has variable future cash flows. The hedges have been deemed to be fully effective resulting in a pre-tax gain of $2 million for the nine months ended September 30, 2007, recorded in other comprehensive income. Upon expiration of these hedges, the amount recorded in other comprehensive income will be reclassified into earnings. The amount expected to be reclassified from other comprehensive income to earnings in the next twelve months is less than $1 million. A deposit in the amount of $9 million, used as collateral for one of the interest rate swaps, is included in restricted cash on the balance sheet. The amount of the deposit required is tied to the market value of the swap. The remaining restricted cash relates to construction deposits.

Energy Trading and Risk Management Activities (non-hedging derivatives). LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended.

The table below summarizes LG&E's energy trading and risk management activities for the nine months ended September 30:

(in millions)	2007	2006
Fair value of contracts at beginning of period, net asset	$ 1	$ 1
Fair value of contracts when entered into during the period	-	2
Contracts realized or otherwise settled during the period	-	(3)
Changes in fair values due to changes in assumptions	(1)	5
Fair value of contracts at end of period, net asset	$ -	$ 5

No changes to valuation techniques for energy trading and risk management activities occurred during 2007 or 2006. Changes in market pricing, interest rate and volatility assumptions were made during both

LG&E adopted the provisions of FIN 48 effective January 1, 2007. At the date of adopting FIN 48, LG&E had $7 million of unrecognized tax benefits, $5 million related to federal income taxes and $2 million related to state income taxes. If recognized, the entire $7 million of unrecognized tax benefits would reduce the effective tax rate.

Included in other liabilities at September 30, 2007, is less than $1 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Furthermore, possible amounts of uncertain tax positions for LG&E that may decrease within the next 12 months total $1 million. The estimated amount of the change in uncertain tax position is based on the expiration of statutes during 2007.

LG&E, upon adoption of FIN 48, adopted a new financial statement classification for interest and penalties. Prior to the adoption of FIN 48, LG&E recorded interest and penalties for income taxes on the income statement in income tax expense and in the taxes accrued balance sheet account, net of tax. Upon adoption of FIN 48, interest and penalties are recorded as operating expenses on the income statement and accrued expenses in the balance sheet, on a pre-tax basis. The interest accrued is based on federal and state large corporate underpayment interest rates.

The amount LG&E recognized as interest accrued related to unrecognized tax benefits in interest expense in operating expenses was less than $1 million at both September 30, 2007 and December 31, 2006. No penalties were accrued by LG&E upon adoption of FIN 48 or through September 30, 2007.

In June 2006, LG&E and KU filed a joint application with the DOE requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that LG&E and KU were selected to receive the tax credit. An additional IRS certification required to obtain the investment tax credit was received in August 2007. LG&E's portion of the tax credit will be approximately $24 million over the construction period of TC2 and will be amortized to income over the life of the related property. In the third quarter of 2007, based on eligible construction expenditures incurred in 2007, LG&E recorded $3 million of federal investment tax credit. The credit recorded decreased current federal income taxes by $3 million, during the three months ended September 30, 2007, and $8 million for the nine months ended September 30, 2007.

Note 6 - Short-Term and Long-Term Debt

All of LG&E's first mortgage bonds were released and terminated in April 2007. Only the tax-exempt revenue bonds issued by the counties remain. Under the provisions for certain of LG&E's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the balance sheets. The average annualized interest rate for these bonds during the nine months ended September 30, 2007 was 3.69%.

During June 2007, LG&E's five existing lines of credit totaling $185 million expired and were replaced with short-term bilateral lines of credit facilities totaling $125 million. There was no outstanding balance under any of these facilities at September 30, 2007. During the third quarter of 2007, LG&E extended the maturity date of these facilities through June 2012.

Dividends on the shares of preferred stock ceased to accumulate on the redemption date and no further dividends will be paid or will accrue on such preferred stock thereafter.
In April 2007, LG&E agreed with Fidelia to eliminate the lien on two secured intercompany loans totaling $125 million.

In April 2007, LG&E entered into two long-term borrowing arrangements with Fidelia in an aggregate principal amount of $138 million. The loan proceeds were used to fund the preferred stock redemption and to repay certain short-term loans incurred to fund the pension contribution made by the Company during the first quarter.

In April 2007, LG&E completed a series of financial transactions impacting its periodic reporting requirements. The pollution control revenue bonds issued by certain governmental entities secured by the $31 million Pollution Control Series S, the $60 million Pollution Control Series T and the $35 million Pollution Control Series U bonds were refinanced and replaced with new unsecured tax-exempt bonds of like amounts. Pursuant to the terms of the bonds, an underlying lien on substantially all of LG&E's assets was released following the completion of these steps.

As of April 27, 2007, LG&E no longer has any secured debt and is no longer subject to periodic reporting under the Securities Exchange Act of 1934.

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in LG&E's Annual Report for the year ended December 31, 2006 (including in Notes 2 and 9 to the financial statements of LG&E contained therein). See the above-referenced notes in LG&E's Annual Report for information regarding such commitments or contingencies.

Construction Program. LG&E had approximately $94 million of commitments in connection with its construction program at September 30, 2007.

In June 2006, LG&E and KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. In December 2005, the Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final order approving the hearing officer's recommendation and upholding the permit. The Sierra Club did not seek judicial review of the final order. In addition, the Company applied for a permit revision to reflect minor design changes to TC2. In October 2007, the Sierra Club submitted comments to the Cabinet objecting to the draft permit revision and attempting to reassert its previous general objections to the generating unit. The Company is currently unable to predict the ultimate outcome of this matter.

agencies in Kentucky have proposed or adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants. To the extent those rules are final, they are not expected to have a material impact on LG&E's power plant operations.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, because the CAIR will result in more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and to continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 to 2006 time period at a cost of $187 million. In 2001, the Kentucky Commission granted recovery in principle of these costs incurred by LG&E under its periodic environmental surcharge review mechanisms.

In order to achieve the emissions reductions mandated by the CAIR and CAMR, LG&E expects to incur additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted recovery in principle of these costs incurred by LG&E under its periodic environmental surcharge review mechanisms. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states, including 11 northeastern U.S. states under the Regional GHG Initiative program and California, have adopted their own GHG emission reduction programs. Substantial efforts to pass federal GHG legislation

Note 9 - Related Party Transactions

LG&E and other subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

LG&E and KU purchase energy from each other in order to effectively manage the load of their retail customers and to satisfy off-system sales. These sales and purchases are included in the statements of income as electric operating revenues and purchased power operating expense. LG&E intercompany electric revenues and purchased power expense is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2007	2006	2007	2006
Electric operating revenues from KU	$18	$23	$71	$67
Purchased power from KU	7	17	33	52

Interest Charges

See Note 6, Short-Term and Long-Term Debt, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

LG&E's intercompany interest expense is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2007	2006	2007	2006
Interest on money pool loans	$1	$-	$3	$1
Interest on Fidelia loans	5	3	12	8

Other Intercompany Billings

E.ON U.S. Services provides LG&E with a variety of centralized administrative, management and support services. These charges include payroll and income taxes paid by E.ON U.S. on behalf of LG&E, labor and overhead charges of E.ON U.S. Services employees performing services for LG&E and vouchers paid by E.ON U.S. Services, including fuel purchases, on behalf of LG&E. The cost of these services are directly charged to LG&E, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned combustion turbines and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of

E.ON U.K. Ltd *(formerly Powergen Ltd, formerly Powergen PLC)*, E.ON U.S. LLC *(formerly LG&E Energy LLC, formerly LG&E Energy Corp.)*, LOUISVILLE GAS & ELECTRIC COMPANY, AND KENTUCKY UTILITIES COMPANY

CASE N0. 2000-095

Response to Summary of Findings, No. 15

"LG&E and KU should annually file their current 3-year capital budgets, including an explanation for any reductions in the capital budget items greater that 10 percent."

Please see the attached table entitled *Three-Year Capital Budgets*.

Transmission System Planning Guidelines

September 11, 2007

E.ON plans its transmission system to meet or exceed the fundamental requirements of a reliable bulk electric system as recommended by the NERC Reliability Standards and the SERC Supplement.

Table 1 describes the contingencies and measurements E.ON utilizes in testing and assessing the performance of its transmission system. Stability of the network should be maintained and cascading outages should not occur. Section 3.1 discusses the applicable thermal limits for Normal and Contingency conditions. Section 3.2 discusses the applicable voltage limits for Normal and Contingency conditions. Section 3.3 discusses modeling issues and how they are considered.

Additionally, E.ON periodically evaluates the risk and consequences of extreme contingency events.

3.1 Thermal Limits

E.ON has established normal and emergency thermal limits (MVA) for each facility based upon its established facility ratings methodology. Flows should be within normal MVA ratings with normal generation and normal transmission system conditions. Flows should be within emergency MVA ratings for each contingency where "No" Loss of Demand Or Curtailed Firm Transfers is indicated. The recorded circuit flow will be the maximum MVA flow of either end. The recorded transformer flow will be the "design output" flow; GSU flows will be measured at the HV side, Step-down transformers will be measured at the LV side and system tie transformers will be measured on the side where the flow exits the transformer. A facility will be overloaded when the MVA flow, rounded to two decimal places, exceeds the applicable rating.

3.2 Voltage Limits

A transmission voltage of 94 percent of the nominal value is the minimum acceptable for normal load service and should be maintained at all load serving busses with normal generation and normal transmission system conditions. Any 500 kV system bus voltage should not exceed 110 percent of the nominal value and any other transmission bus voltage should not exceed 105 percent of the nominal value.

Transmission level voltage at the major power plants should be maintainable with normal generation and normal transmission system conditions during summer and winter peak load conditions, as follows:

Table 2
Normal Plant Voltages at System Peak Load

Power Plant	Transmission Bus (kV)	Scheduled Voltage (kV)	Per Unit Voltage
Brown	Brown N 138	142	1.029
Cane Run	Cane Run Sw 138	138	1.000
Ghent	Ghent 345	355	1.029
Green River	Green River 138	142	1.029
Mill Creek	Mill Creek 345	352	1.020
Trimble County	Trimble Co 345	352	1.020
Elmer Smith	Smith 138	142	1.029

A transmission voltage of 90 percent of the nominal value is the minimum acceptable for contingency load service and should be maintained at all load serving busses during any transmission system contingency or generation and transmission system contingency.

Generators and plant auxiliary systems are generally designed to operate within +/- 5% of the nameplate or nominal voltage. Table 3, on the following page, shows the required transmission level voltage at each generating unit to maintain generator voltage and auxiliary bus voltage above 95% of nominal with the unit operating at maximum MW and MVAR output. The transmission level voltage should exceed the voltage specified in Table 3 during any contingency condition. Only on-line generators are applicable to the analysis.

3.3 Modeling Considerations

Seasons Assessed – The power flow analysis used in the Planning process will evaluate the adequacy of the transmission system to provide Network Integration Transmission Service using summer and winter peak load models and will be documented by an annual Transmission Expansion Plan. Transmission constraints that may occur during shoulder and off-peak conditions will be managed via the ATC process, including potential redispatches. System Impact Studies for Generator Interconnections and any dynamic analysis will also utilize other seasonal and light load models, as appropriate.

Generation Dispatch - Replacement generation required to offset unit outages should be simulated from the most restrictive of internal sources, AEP, Cinergy, and/or TVA. Maximum plant output will be achieved by simulating an outage of one unit at another plant and prorating additional reductions, as necessary, across all on-line units at other plants

Single Contingency - A single contingency may outage multiple transmission components in the common zone of relay protection. Reclosure of the non-faulted components will be evaluated but is not required if violations occur as a result of the post-fault restoration. Procedures should be developed and documented if the component is not to be reclosed.

Load Restoration and Switching - Post-fault conditions and conditions after load restoration and or switching should be evaluated. Post-contingency operator-initiated actions to restore load service must be simulated. Load that is off-line as a result of the contingency being evaluated may be switched to alternate sources during the restoration process but load should not be taken off-line to perform switching. Post-contingency operator-initiated actions may be simulated to reduce the flow through transformers or increase voltages but not to reduce line flows.

Transmission Capacitor Switching - Transmission capacitor status (on/off) should be simulated consistent with automatic voltage control (on/off) settings and operating practice during normal transmission system conditions. Capacitor switching should not be simulated to eliminate voltage violations that result from a contingency unless the automatic voltage control would cause the capacitor to operate.

Off-Peak Voltage Control – Transmission system changes to manage Off-Peak voltages will be identified and evaluated using operation data. Seasonal adjustment of fixed taps on transmission transformers should not be required to control voltages within the acceptable ranges. Switching EHV system facilities out of service to reduce off-peak voltages is undesirable.

Voltage Fluctuations – E.ON limits voltage fluctuation due to customer load variations and transmission capacitor switching to a maximum of 3% during normal transmission conditions and 6% during single transmission contingencies. These maximum values apply if the fluctuation occurs less frequently than once per hour. If more frequent, the maximum allowable voltage fluctuation is reduced as per the Limits of Flicker published in IEEE Std 519. The maximum normal and contingency fluctuations are limited to the "Border Line of Visibility" and the "Border Line of Irritability" curves, respectively.

4 Impacted Facilities

Generator Interconnections, Transmission to Transmission Interconnections, Network Integrated Transmission Service, and Long-Term Firm Point to Point (1 yr or longer) Requests require studies to identify facilities that are impacted. The following minimum requirements are used to identify Impacted Facilities:

- the flow increases by 1.00% or more,
- the voltage decreases by 0.50% or more, or
- the short circuit current increases by 5.00% or more.

Impacted Facilities that are identified with pre-existing criteria violations (simulations on base case models) will be evaluated to determine the upgrade required to mitigate the pre-existing violation. Such upgrade and associated rating will be used to determine if additional costs are required due to the Request.

RESEARCH

Summary:
Kentucky Utilities Co.

Publication date: 03-Jan-2007
Primary Credit Analyst: Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com
Secondary Credit Analyst: Brian Kahn, New York; brian_kahn@standardandpoors.com

Credit Rating: BBB+/Stable/A-2

Rationale

The ratings on Kentucky Utilities Co. are based on the credit profile of parent E.ON U.S. LLC. The E.ON U.S. ratings reflect the credit characteristics of the two operating utilities in Kentucky, Kentucky Utilities and Louisville Gas & Electric Co., and the company's focus on operating the fully integrated utilities, with implicit support for credit quality from E.ON U.S.' ultimate parent, E.ON AG (AA-/Watch Neg/A-1+), factored into the analysis. E.ON has prominently expressed its support for E.ON U.S. and its intent to maintain its U.S. presence.

E.ON U.S.'s business risk profile is rated '6' (satisfactory), and its financial risk profile is considered intermediate. (Utility business risk profiles are categorized from '1' (excellent) to '10' (vulnerable).)

The company's satisfactory business risk profile is supported by low-risk, regulated, and financially sound gas distribution and electric operations, efficient generation facilities that allow for competitive rates, and a supportive regulatory environment. The company's electric operations benefit from a fuel adjustment mechanism and an environmental cost recovery mechanism, while the company's smaller gas operations benefit from a weather normalization adjustment clause and a cost-of-gas cost adjustment mechanism. Together, these mechanisms reduce exposure to environmental requirements, weather, and potential volatility in natural gas prices, all of which normally raise credit-related concerns.

Unregulated operations, a large industrial customer base, and coal-fired generation facilities that require large environmental expenditures detract from the business risk profile. E.ON U.S. may significantly reduce its unregulated operations if a preliminary agreement to exit its involvement with Big Rivers Electric Corp. is finalized. It is anticipated that Big Rivers will obtain control of its plants in September 2007. Currently, E.ON U. S. leases and operates four of Big River's power plants.

Liquidity

STANDARD & POOR'S RatingsDirect

RESEARCH

Summary:
Louisville Gas & Electric Co.

Publication date: 05-Jan-2007
Primary Credit Analyst: Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com
Secondary Credit Analyst: Brian Kahn, New York; brian_kahn@standardandpoors.com

Credit Rating: BBB+/Stable/NR

Rationale

The ratings on Louisville Gas & Electric Co. are based on the credit profile of parent E.ON U.S. LLC. The E. ON U.S. ratings reflect the credit characteristics of the two operating utilities in Kentucky, Louisville Gas & Electric and Kentucky Utilities Co., and the company's focus on operating the fully integrated utilities, with implicit support for credit quality from E.ON U.S.' ultimate parent, E.ON AG (AA-/Watch Neg/A-1+), factored into the analysis. E.ON has prominently expressed its support for E.ON U.S. and its intent to maintain its U.S. presence.

E.ON U.S.'s business risk profile is rated '6' (satisfactory), and its financial risk profile is considered intermediate. (Utility business risk profiles are categorized from '1' (excellent) to '10' (vulnerable).)

The company's satisfactory business risk profile is supported by low-risk, regulated, and financially sound gas distribution and electric operations, efficient generation facilities that allow for competitive rates, and a supportive regulatory environment. The company's electric operations benefit from a fuel adjustment mechanism and an environmental cost recovery mechanism, while the company's smaller gas operations benefit from a weather normalization adjustment clause and a cost-of-gas cost adjustment mechanism. Together, these mechanisms reduce exposure to environmental requirements, weather, and potential volatility in natural gas prices, all of which normally raise credit-related concerns.

Unregulated operations, a large industrial customer base, and coal-fired generation facilities that require large environmental expenditures detract from the business risk profile. E.ON U.S. may significantly reduce its unregulated operations if a preliminary agreement to exit its involvement with Big Rivers Electric Corp. is finalized. It is anticipated that Big Rivers will obtain control of its plants in September 2007. Currently, E.ON U. S. leases and operates four of Big River's power plants.

Liquidity

STANDARD
&POOR'S

RATINGSDIRECT®

June 12, 2007

Research Update:
E.ON U.S. 'BBB+' Rating Affirmed, Outlook Stable

Primary Credit Analyst:
Todd A Shipman, CFA, New York (1) 212-438-7676,todd_shipman@standardandpoors com

Secondary Credit Analyst:
Brian Kahn, New York,brian_kahn@standardandpoors com

Table Of Contents

provides a $200 million credit facility to E.ON U.S., to ensure funding availability for its money pool.

Outlook

The stable outlook on E.ON U.S. is based on continued support from E.ON AG and a corporate strategy that maintains a primarily low-risk, utility-based business risk profile. The ratings and outlook for E.ON U.S. and its subsidiaries are linked to those on E.ON. The importance of E.ON's U.S. operations to its group strategy remains a factor in the ratings on E.ON U.S. Any change in the parent's attitude toward its U.S. holdings or in Standard & Poor's perception of the parent's support could lead to a rating change. Completion of the Big Rivers transaction would lessen the company's exposure to unregulated activities and could lead to an improved business risk profile and higher ratings.

Ratings List

Ratings Affirmed

E.ON U.S. LLC	
Corporate credit rating	BBB+/Stable/--
Kentucky Utilities Co.	
Corporate credit rating	BBB+/Stable/A-2
Senior secured debt	BBB+
Preferred stock	BBB-
Commercial paper	A-2
Louisville Gas & Electric Co.	
Corporate credit rating	BBB+/Stable/--
Senior unsecured debt	BBB+
Preferred stock	BBB-

Complete ratings information is available to subscribers of RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

Moody's Investors Service

Issuer Comment: E. ON U.S. LLC

Moody's comments on E.ON U.S. LLC and its subsidiaries

Moody's Investors Service said that the downgrade yesterday of the senior unsecured rating of E.ON AG to A2 from Aa3 does not trigger a change in the rating or outlook of E.ON U.S. LLC (A3 Issuer rating) and its subsidiaries Louisville Gas & Electric Company (LG&E: A2 Issuer Rating), Kentucky Utilities (KU: A2 Issuer Rating) and E.ON U.S. Capital Corp. (A3 senior unsecured debt).

The ratings for E.ON U.S. LLC and its subsidiaries reflect the substantial degree to which they maintain an independent credit profile that is supported by the primarily regulated nature of their underlying cash flows. Specifically, core financial metrics (incorporating Moody's standard analytical adjustments) remain positioned within the ranges outlined in our Rating Methodology for A-rated utilities with medium business risk profiles. LG&E's ratio of FFO to debt and FFO interest coverage were approximately 24% and 6 times for the twelve months ended December 31, 2006. KU's credit metrics for the same period were slightly stronger at approximately 26% and greater than 7 times, respectively.

The credit analysis of E.ON U.S. LLC and its subsidiaries also considers inter-company funding support in the form of loans from other subsidiaries of E.ON AG. Due to the magnitude of on-going inter-company funding the ratings and outlook of the U.S. entities could be affected if E.ON AG's senior unsecured rating were to be downgraded further from its current A2 level.

The rating outlook for E.ON AG, E.ON U.S. LLC, LG&E, KU and E.ON U.S. Capital Corp. is stable.

E.ON U.S. LLC is headquartered in Louisville, Kentucky.

Contacts	Phone
Scott Solomon/New York	201-915-8764
Richard E. Donner/New York	212-553-7226
Michael Rowan/New York	212-553-4465
William L. Hess/New York	212-553-3837

Moody's Investors Service

Global Credit Research
Credit Opinion
10 JUL 2007

Credit Opinion: Kentucky Utilities Co.

Kentucky Utilities Co.

Lexington, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A2
Senior Secured Shelf	(P)A1
Ult Parent: E.ON AG	
Outlook	Stable
Bkd Sr Unsec Bank Credit Facility -Dom Curr	A2
Senior Unsecured MTN -Dom Curr	A2
Commercial Paper -Dom Curr	P-1
Parent: E. ON U.S. LLC	
Outlook	Stable
Issuer Rating	A3

Contacts

Analyst	Phone
Scott Solomon/New York	1.212.553.1653
Richard E. Donner/New York	
William L. Hess/New York	

Opinion

Company Profile

Kentucky Utilities (KU) is a regulated public utility engaged in the generation, transmission and distribution of electricity. It provides electricity to approximately 501,000 customers in 77 counties in central, southeastern and western Kentucky and to approximately 30,000 customers in 5 counties in southwestern Virginia. KU's coal-fired electric generating plants produce most of KU's electricity. In Virginia, KU operates under the name Old Dominion Power Company.

KU is a wholly-owned subsidiary of E.ON U.S. LLC (A3 Issuer Rating). E.ON U.S. is an indirect wholly-owned subsidiary of E.ON AG (A2 senior unsecured). KU's affiliate Louisville Gas and Electric Company (LG&E: A2 Issuer Rating), is a regulated public utility also operating in Kentucky. Although LG&E and KU are separate legal entities, they are operated as a single, fully integrated system and provide the majority of the consolidated earnings and cash flow of E.ON U.S. LLC.

Rating Rationale

Kentucky Utilities Company's (KU) A2 Issuer Rating is based on the utility's strong financial profile, favorable cost positions and balanced regulatory environments. Core financial metrics (incorporating Moody's standard analytical adjustments) remain positioned within the ranges outlined in our Rating Methodology for A-rated utilities with medium business risk profiles. Specifically, KU's ratio of FFO to debt and FFO interest coverage for the twelve months ended December 31, 2006 were approximately 26% and greater than 7 times respectively.

KU has an environmental cost recovery mechanism in its electric rates that allow for the recovery of environmental costs required to meet federal and state statutes. This is important given that KU and LG&E expect their combined near-term environmental capital spending to exceed $1 billion through 2009. The utility also benefits from a fuel adjustment clause that eliminates supply cost volatility.

The credit analysis of KU considers intercompany funding support in the form of loans from other subsidiaries of E.ON AG. Due to the magnitude of on-going intercompany funding the ratings and outlook of KU could be affected if E.ON AG's senior unsecured rating were to be downgraded from its current level.

Moody's Investors Service

Global Credit Research
Credit Opinion
10 JUL 2007

Credit Opinion: Louisville Gas & Electric Company

Louisville Gas & Electric Company

Louisville, Kentucky, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	A2
Ult Parent: E.ON AG	
Outlook	Stable
Bkd Sr Unsec Bank Credit Facility -Dom Curr	A2
Senior Unsecured MTN -Dom Curr	A2
Commercial Paper -Dom Curr	P-1
Parent: E. ON U.S. LLC	
Outlook	Stable
Issuer Rating	A3

Contacts

Analyst	**Phone**
Scott Solomon/New York	1.212.553.1653
Richard E. Donner/New York	
William L. Hess/New York	

Opinion

Company Profile

Louisville Gas and Electric Company (LG&E) is a regulated public utility that supplies natural gas to approximately 324,000 customers and electricity to approximately 398,000 customers in Louisville and adjacent areas in Kentucky. LG&E's coal-fired electric generating plants produce most of LG&E's electricity.

LG&E is a wholly-owned subsidiary of E.ON U.S. LLC (A3 Issuer Rating). E.ON U.S. is an indirect wholly-owned subsidiary of E.ON AG (A2 senior unsecured). LG&E's affiliate Kentucky Utilities (KU: A2 Issuer Rating), is a regulated public utility also operating in Kentucky. Although LG&E and KU are separate legal entities, they are operated as a single, fully integrated system and provide the majority of the consolidated earnings and cash flow of E.ON U.S.

Rating Rationale

LG&E's A2 Issuer Rating is based on the utility's strong financial profile, favorable cost positions and balanced regulatory environments. Core financial metrics (incorporating Moody's standard analytical adjustments) remain positioned within the ranges outlined in our Rating Methodology for A-rated utilities with medium business risk profiles. Specifically, LG&E's ratio of FFO to debt and FFO interest coverage for the twelve months ended December 31, 2006 were approximately 24% and greater than 6 times respectively.

LG&E has an environmental cost recovery mechanism in its electric rates that allow for the timely recovery of environmental costs required to meet federal and state statutes. This is important given that LG&E and KU expect their combined near-term environmental capital spending to exceed $1 billion through 2009. The utility also benefits from a fuel adjustment clause that eliminates supply cost volatility.

The credit analysis of LG&E also considers intercompany funding support in the form of loans from other subsidiaries of E.ON AG. Due to the magnitude of on-going intercompany funding the ratings and outlook of LG&E could be affected if E.ON AG's senior unsecured rating were to be downgraded from its current level.

The challenges ahead for LG&E include supporting the level of demand in its service territory and maintaining an adequate reserve margin. To that end, it has begun construction of a 750-megawatt coal-fired generating station of

Kentucky Utilities Company
And
Louisville Gas & Electric Company

Analysis of Supply-Side Technology Alternatives

Prepared by

Generation Systems Planning

November 2004

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS & ELECTRIC COMPANY
ANALYSIS OF
SUPPLY-SIDE TECHNOLOGY ALTERNATIVES

INTRODUCTION

This study evaluated several supply-side technology costs and performance estimates for currently available and emerging technologies. The study was conducted by first constructing optimal (least-cost) operation for each technology at various levels of utilization. A detailed evaluation (using production costing computer models) of all currently available/emerging technologies was impractical due to the large number of possible alternatives and the significant amount of time required for computer simulation if each were modeled individually. Therefore, it was necessary to reduce the list of possible technology alternatives to a more manageable size. To achieve this, a discussion of the sources for, and adjustments to, the data presented within this analysis and a brief description of each generating technology is presented. This is followed by a description of the levelized screening methodology and associated sensitivities. Finally, the basis for recommending one technology over another is presented and those technologies suggested for additional computer simulation are identified.

DATA SOURCES

Black & Veatch gathered information on several technology alternatives and submitted to the Companies a final examination in September 2004. The document included technical descriptions for all technologies, detailed capital costs, performance expectations, emission rates, and O&M costs for conventional generation alternatives (pulverized coal, simple and combined cycle combustion turbines). The non-conventional technologies (renewable energy, waste-to-energy, advanced coal and combustion turbines, and energy storage systems) have the same data as the conventional alternatives but in less detail due to their maturity and infrequent use as

2,400 psig for conventional (subcritical) boiler designs, improving the efficiency by 10 percent (to around 45 percent overall). This evaluation contains seven "Greenfield" pulverized coal options, which include three subcritical units varying from 250 MW to 500 MW and four supercritical units ranging in size from 500 MW to 750 MW. Of the seven coal options, three of these were considered high sulfur (4.5 percent or more sulfur content) and included both a subcritical and a supercritical unit of 500 MW size, and a 750 MW supercritical unit.

2. *Circulating Fluidized Bed Combustion*

Fluidized bed combustion (FBC) boilers with steam turbine generators have been widely used in the United States, Europe, and Japan since the mid-1980s for independent power/cogeneration and utility power. There are two types of FBC: Circulating FBC (CFBC) and Pressurized FBC (PFBC).

CFBC involves injecting a portion of the combustion air through the bottom of a water-cooled bed consisting of fuel, limestone, and ash. This upwardly flowing air causes the layers to mix in a turbulent environment and to behave in a fluid-like manner. CFBC technology allows units to burn a diversity of low-grade coal and non-coal fuels in addition to high-grade coals without costly control equipment such as FGDs and SCRs to satisfy environmental emission limitations. The low combustion temperatures reduce thermal NO_x formation while the ability to introduce limestone directly into the furnace controls SO_2 emissions.

CFBC has matured to where it is now comparable to most modern solid fuel fired plants, including conventional, pulverized coal units. Both a 250-MW unit and 500-MW unit were included in this study, each of which was assumed to have a capacity factor of 100 percent.

included in the study has two trains, each of which would contain all components listed for the 250-MW unit. A capacity factor of 85 percent was assumed for both units.

Liquid/Gas-Fueled Technologies

1. Reciprocating Engine

Reciprocating engines have been used for a number of years to provide primary and backup sources of electrical generation for power, industrial, and many other applications. Medium speed engines, operating at less than 1,000 rpm, are typically used for power generation because of higher efficiencies and lower O&M costs. Advantages of reciprocating engines are static heat rates from 50 to 100 percent load, excellent load-following characteristics, guaranteed emission rates maintained at operating levels down to 25 percent load, and typical startup times for larger reciprocating engines of only 15 minutes. Disadvantages of reciprocating engines include high uncontrolled air pollutant emission rates and unproven emission control technologies.

Two types of reciprocating engines were included in this study: spark ignition engines and compression ignition engines. Spark ignition engines operate on gaseous fuel such as natural gas, propane, or waste gases from industrial processes while compression ignition engines operate on liquid fuels such as diesel. The study includes a 5-MW spark ignition engine and a 10-MW compression ignition engine. A capacity factor of 50 percent was used for each type of engine.

2. Simple Cycle Combustion Turbines

Simple cycle combustion turbines generate power by compressing ambient air and then heating the pressurized air (to at least 2000°F) by injecting and burning natural gas or oil, and forcing the heated gases to expand through a turbine. The turbine drives the air compressor and lower NO_x and carbon monoxide (CO) emissions, improved efficiency, and potentially greater operating flexibility if duct burners are used. Disadvantages are reduced plant reliability and increased maintenance, increase in overall staffing requirements due to added plant complexity, and volatility of natural gas prices.

Several combined cycle configurations were evaluated in this study ranging in capacity from 118.5 MW to 483.9 MW at 90°F. A capacity factor of 100 percent was used for each combined cycle configuration evaluated.

Along with the conventional GE and Westinghouse machines currently available, three other advanced combined cycle technologies (humid air turbine, Kalina Cycle, Cheng Cycle) were also included. These technologies are generally considered developmental, but offer significant potential for efficiency improvements over conventional technologies.

The humid air turbine (HAT) cycle utilizes a natural gas-fired intercooled regenerative cycle with a saturator that adds considerable moisture to the compressor discharge air (such that the combustor inlet flow contains 20 to 40 percent water vapor). The turbine exhaust is further heated by a recuperator (using turbine exhaust) before being sent to the combustor. Water vapor adds to the turbine output while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. The HAT reviewed herein is rated at 450 MW and has a capacity factor of 70 percent.

The Kalina Cycle combustion turbine involves injecting ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages based on non-isothermal boiling and condensing behavior of the dual component fluid, coupled with the ability to alter the ammonia concentration at various points in the cycle. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection. The cycle is similar in nature to the combined cycle process except exhaust gas from the combustion turbine enters a heat housed in a single unit about the size of a refrigerator. Microturbines can operate on a wide range of fuels, including natural gas, ethanol, propane, biogas, and other renewable fuels. Design enhancements such as catalytic combustion and air bearings further reduce already low emissions and maintenance requirements.

The baseload and peaking microturbines considered in this evaluation are each rated 30 kW, and at that size are suitable to supply load to individual customers only. The capacity factor used for the evaluation of microturbines was 10 percent.

5. *Fuel Cell*

Fuel cells electrochemically convert hydrogen-rich fuel, typically natural gas, to direct current (DC) electricity. Inverters are required to convert the DC power to AC. Fuel cell construction is inherently modular making it easy to size power plants tailored to the utility's load growth and the constraints of the plant site.

Each cell consists of an anode, cathode, and an electrolyte. Fuel cells oxidize a fuel at the anode, which releases electrons into an electrical circuit. Simultaneously, water and heat are produced at either the anode or cathode depending on the electrolyte used. Fuel cells, unlike batteries, do not consume their electrodes with use, but only the fuel and oxygen (in the air) supplied to them.

There are four major fuel cell types in development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most mature of the four is the phosphoric acid fuel cell (PAFC). PAFC plants range from 200 kW to 11 MW in size and have efficiencies on the order of 40 percent. Since fuel cells operate at constant temperature and pressure regardless of load, the thermal energy liberated by the electrochemical reaction can be used in thermal

Renewable Resource Technologies

1. Wind Energy

Wind is converted to power via a rotating turbine and generator. Utility-scale wind systems consist of multiple wind turbines ranging in size from 100 kW to 2 MW. A complete wind energy system contains several wind turbines and has a total rating between 5 MW and 300 MW. Capacity factors range from 25 to 40 percent and depend upon the wind regime in the area. Therefore, wind energy is considered an intermediate load technology that cannot be relied upon as firm capacity. Wind power is rated on a scale of Class 1 to Class 7, with Class 7 representing an area with substantial wind speeds (20 to 27 mph). A Class 3 rating or above is needed in order for it to be considered economically feasible. The Companies' service area experiences wind ratings of Class 1 and 2, which restricts the economic feasibility of this technology.

Despite the obvious limitations, a 50 MW wind system with a 33 percent capacity factor was considered for this evaluation.

2. Solar

Solar energy conversion technologies capture the sun's energy and converts it to thermal energy (solar thermal) or electrical energy (solar photovoltaic), which drives the device (turbine, generator, or heat engine) for electrical generation. Sunlight is concentrated with mirrors or lenses to achieve the high temperatures needed for solar thermal power systems. Solar thermal technologies currently in use include the following: parabolic trough, parabolic dish, solar chimney, and central receiver. Parabolic trough represents the vast majority of systems installed although most of these installations are less than 50 kW. Current grid-connected solar photovoltaic systems are generally below 200 kW with capacity factors of around 20 percent.

percent. Efficiencies of biomass plants are lower when compared to modern coal units due to lower heating values and higher moisture contents in the fuel. Resources economically located within a deliverable area limit the plant size. The most efficient and economically attractive options for electrical generation from biomass resources include co-fired projects which would only offset fossil fuel consumption. Additionally, there are several concerns about the negative impact of co-firing on plant operations, including impacts on capacity, boiler performance, and premature poisoning of air pollution control equipment.

The biomass alternative included in this evaluation is a co-fired facility with a 27.5 MW output and a capacity factor of 80 percent.

4. Geothermal

Geothermal power plants use heat from the earth to generate steam and drive turbine generators for the production of electricity. The production of geothermal energy in the US currently ranks third in renewable energy sources, following hydroelectric and biomass. There are three types of geothermal power conversion systems in common use, including dry steam, flash steam, and binary cycle steam. Capital costs of geothermal facilities can vary widely as the drilling of individual wells can cost as much as four million dollars, and the number of wells drilled depends on the success of finding the resource. Variable O&M costs include the replacement of production wells.

Geothermal power is limited to locations where geothermal pressure reserves are found. Most geothermal reserves can be found in the western portion of the United States, but virtually no geothermal resources exist in this area. However, the Companies' service territory has a sufficient amount of low-temperature resources to be suitable for heat pump.

A 30 MW binary cycle unit with an 80 percent capacity factor is included in this study.

are generally less than 50 MW with a capacity factor between 60 and 80 percent. Mass burning of ISW was once seen as an environmentally and economically sound alternative for dealing with the shrinking landfill space in the United States. However, environmental concerns over pollutants, high capital costs, and public opposition make it doubtful that new WTE facilities utilizing MSW will be constructed in the near future.

In spite of the apparent difficulties associated with burned MSW for generation of energy, a 7-MW unit with a 70 percent capacity factor was considered in this evaluation.

RDF is an evolution of MSW technology in which the waste is sorted and processed into fluff or pellets. It is preferred in many refuse-to-energy applications due to its ability to be combusted with technologies traditionally used for coal. Combustion temperatures for MSW and RDF must be kept lower than 800°F to minimize boiler tube degradation caused by chlorine compounds in the flue gas. Unit size, capacity factors, and environmental concerns for RDF are similar to MSW characteristics. As a result, a 7-MW unit fueled by RDF with a capacity factor of 70 percent was also considered in the evaluation process.

LFG is a valuable energy source that can be utilized in several applications, including power production, and is considered to be a mature WTE technology. LFG is produced by the decomposition of wastes stored in landfills where it is collected and piped from wells, filtered, and then compressed. Although gas is produced when decomposition begins within a landfill, it may be several years before there is an adequate supply of gas to fuel an electric generator. Later, as the site ages, gas production (as well as the quality of the gas) declines to the point at which power generation is no longer economic. In the case of a typical well-engineered and well-operated landfill, gas may be produced for as many as 50 to 100 years, but electricity production may be economically feasible for only 10 to 15 years, Power can be generated via a combustion turbine, factor is that the Companies have no boilers in their system that would be similar to any of the styles required to use TDFs.

Nevertheless, the TDF alternative included in this evaluation is a co-fired system and is rated at 50 MW with capacity factor of 70 percent.

Energy Storage Technologies

1. Pumped Hydro Energy Storage (PHES)

Central hydro energy storage is the oldest and most prevalent of the central station energy storage options and requires a setup similar to conventional hydroelectric facilities. Conventional PHES plants typically use an upper and lower reservoir. Off-peak electrical energy is used to pump water from the lower reservoir to upper reservoir. When the energy is required during peak hours, the water in the upper reservoir is converted to electricity as the water flows through a turbine to the lower reservoir. Environmental impacts from PHES can be significant if improperly sited and geologic conditions preclude many areas from consideration of this technology. Additionally, increasingly restrictive environmental regulations and established uses of the river systems in proximity to the Companies may further hamper consideration of this alternative. Finally, high capital costs and extended lead times are significant disadvantages that must be accounted for when considering this alternative.

For the PHES unit used in this screening analysis, the nameplate rating corresponds to 500 MW. Pumped hydro is considered a viable option to serve intermediate load levels but the low capacity factor (13 percent in this evaluation) makes it difficult for this technology to compete with other peaking technologies.

2. Battery Energy Storage (BES)

With a BES unit, off-peak energy is used to charge a battery for use during peak periods.

Other Technologies

1. Ohio Falls Expansion

Expansion of the Ohio Falls Station by the additions of Units 9 and 10 into existing empty bays was included as an option in the screening analysis. This expansion included two 209.2" diameter propeller units housed in an extension of the existing powerhouse. These units would rotate at 149 rpm and have a maximum turbine output of 16.8 MW (summer rating of 5 MW and dependant upon river flow) each. Based upon historical river flow, expected energy from the expansion units would be approximately 74 GWH annually. Therefore, the maximum capacity factor would be 25 percent. Estimated capital cost for Units 9 and 10 is $46.7 million combined. The Ohio Falls Station is considered a run-of-the-river facility where nature and the Army Corps of Engineers control the river flow. Therefore, the energy production of the facility can vary significantly and may not be available at the time of the Companies' peak needs.

ANALYSIS OVERVIEW

The Companies screening analysis consists of 47 generation alternatives developed by Burns & McDonnell, Voith Siemens, Cummins & Barnard, WV Hydro and Black & Veatch. The screening process involves utilizing specific unit operating data such as unit ratings, heat rate, operation and maintenance expenses, and capacity factors to accurately assess lifetime costs associated with owning and operating each technology type and size.

Sensitivities are utilized to provide valuable information on how each technology will perform under various operating conditions. Some of the sensitivities contained in this analysis are based on variations in capital cost, technology operating efficiency (measured by heat rate), and fuel cost. Each of the previously mentioned sensitivities has three possible scenarios: base, low, and high, which results in 27 sensitivity combinations. The remaining sensitivity considered in the screening evaluation concerns emissions. The base case analysis includes costs associated with NO_x and SO_2 emissions. CO_2 emissions are a possibility in the future and an evaluation which considers NO_x, SO_2, and CO_2 emissions is included in this analysis as an alternative to the base case.

An analysis comparing total levelized costs for all technologies as a function of capacity factor was also performed. This additional level of analytical scrutiny results in 891 (i.e., 27 cases x 11 capacity factor ranges x 3 least cost options = 891) "opportunities" for each technology to be identified as one of the three least cost options. Total costs are evaluated over a 30-year planning period in all possible case combinations.

Descriptions of the sensitivity analysis, resulting scenarios evaluated, screening analysis, and the levelized analysis are included in the following sections. The final portion of this emission cost adders for NO_x are applied to the variable O&M expense for all applicable technologies. SO_2 emission costs are based upon the Cantor-Fitzgerald allowances prices and estimates from 2004 through 2010, with prices thereafter assumed to escalate by two percent annually.

A 2004 SO_2 allowance price of $172/ton and a NO_x allowance price of $3125/ton were the starting allowance values used in the analyses (source: Cantor-Fitzgerald).

The second case evaluates potential additional cost of CO_2 emissions in addition to costs associated with SO_2 and NO_x emissions. Rising concentrations of greenhouse gases may be responsible for undesirable climate changes, and legislation to restrict CO_2 emissions (a greenhouse gas) has been *proposed*. One proposed solution is the implementation of a carbon tax which could impact the least-cost options resulting from this screening analysis.

The magnitude of proposed carbon tax varies significantly. A current expectation for a carbon tax is in the range of $10 to $40 per ton of carbon emitted and is based on external analysis. As with the SO_2 adder, the carbon cost adder was added to the fuel cost of the technology as discussed below.

1. Capital Cost Sensitivity

Black & Veatch has two technology ratings that can be used to adjust the capital cost for each technology type. The technologies are classified as either conventional or non-conventional generating alternatives and take into account the maturity level of the technologies. Conventional generation alternatives are currently available, widely-used and proven technologies whereas non-conventional generation alternatives are still in development or have not been widely implemented or operated. Both ratings take into consideration the issue of uncertainty in cost and performance data. From there, the capital costs supplied by Black & Veatch for each technology size are

3. *Fuel Cost*

The third sensitivity conducted in the screening analysis considers the cost of fuel consumed by each technology. The Companies develop 30-year base fuel forecasts for all fuels that are either used or could be used at existing plants. Sensitivity fuel forecasts are then developed depicting high and low fuel cost scenarios. Base coal price forecasts are adjusted by data received from Global Insight for the high and low fuel cost sensitivities. Representative fuel costs for each technology screened were obtained from the base and sensitivity fuel forecasts and are shown in Exhibit 2(a).

As previously described, in an effort to include the impact of SO_2 emissions in the screening study, an adder was applied to the coal prices shown in Exhibit 2(a). The adder represents, on a cents per MBtu basis, the annual cost of SO_2 allowances. Only technologies whose primary fuel is coal have the adder. The sulfur content of the Low and High Fuel Forecasts was assumed to be equal to that of the Base Fuel Forecast. Therefore, once the adder was determined for the Base Fuel Forecast, it could be applied to both the Low and High Forecasts without any further adjustments. Exhibit 2(b) details the calculation of the SO_2 adder.

Inclusion of the SO_2 adder increases the fuel cost from 0.5 to 6 Cents per MBtu depending on the year and sulfur content. The small impact of the SO_2 adder is due to the fact that all technologies being considered in the analysis have very low SO_2 emissions resulting from either pre/post combustion removal processes. Addition of the SO_2 adder to the Base, Low and High Fuel Forecasts results in the fuel costs used in this analysis. The specific fuels utilized by each technology evaluated in this analysis are identified in Exhibit 2(c).

SCREENING ANALYSIS

The least-cost operation of the technologies presented in this study occurs over significantly different capacity factors. Therefore, an analysis that compares the total cost for each technology as a function of capacity factor is required. As previously discussed, the cost data for all technologies in this analysis originate from Black & Veatch or were derived based on information and/or cost estimates received by the Companies.

Based on the results of economic analysis performed in the Companies' 2002 IRP Supply-Side Screening report and using recommendations prepared by Burns & McDonnell, the Companies have selected design parameters for the Trimble County Unit 2. The construction of a 732 MW supercritical pulverized coal unit was determined to represent the most economically viable option and it was evaluated using the same considerations as the other technologies evaluated in the screening process. Beside the Trimble County Unit 2 option, there were several other coal options in the screening analysis for future coal units. Next, each technology listed in Exhibit 3, regardless of viability or technical maturity, was evaluated over a 30-year planning period in all 27 cases for both the Base Case Analysis and the Alternative Analysis with CO_2 Impact.

No technologies were excluded from the screening analysis based solely on technical maturity, practicality, or feasibility. For example, even though climatic information for Kentucky suggests wind turbine technology would not be a practical supply-side option in Kentucky, wind turbine technology was not excluded from the analysis.

Several technologies were limited to maximum capacity factors based on design characteristics of the option and their application to the Companies' service territory. The pumped hydro energy storage, battery energy storage, and compressed air energy storage options were limited to a 20 percent capacity factor based on design characteristics of the technologies supplied

LEVELIZED SCREENING METHODOLOGY AND RESULTS

1. Base Analysis with SO_2 and NO_x Impact

A 30-year levelized cost methodology was utilized in the base analysis. An annual total cost, comprised of capital, fixed O&M, variable O&M, fuel and other costs, is determined for each technology over a range of capacity factors from 0-100 percent in 10 percent increments. For each technology, levelized costs in $/kW at varying capacity factors were then compared and least-cost technologies at each capacity factor increment were determined. Levelization allows for the cost of each technology to be compared over the 30-year life of each project. A non-levelized analysis considers costs of owning and operating generating units for only a single year. Comparison of cost over the life of each technology is more accurate because of differing annual escalation rates for fuel, O&M and capital associated with determining the total annual cost of each technology. Exhibits 4 and 5 include relevant information, which when utilized in conjunction with Exhibits 2 and 3, allow replication of the results presented here. Exhibit 4 provides a complete source of equations used in the levelization process. Exhibit 5 provides the Adjusted 30-year Levelization Factor (Adj. L_N) for the Base Fuel Forecast and other miscellaneous information referred to within the equations of Exhibit 4. Adjusted L_Ns for the Low and High Fuel Forecasts can be determined in a similar manner.

Using the equations of Exhibit 4 and data contained within Exhibits 2(a)-2(d), Exhibit 3, and Exhibit 5, the total 30-year levelized cost ($/kW-yr in 2004 dollars) of each technology was calculated for each capacity factor increment. The results of this process are shown in pages 1 through 27 of Exhibit 6. Least-cost technologies over all ranges of capacity factors have been identified at the bottom of each case exhibit and are shaded in the tables. Technology capacity factors shown in pages 1 through 27 of Exhibit 6 were limited to the maximum allowed by the technology and/or environment in which they operate as previously discussed. For easy reference,

Table 3
Second and Third Least-Costly Technologies
In At-Least One Sensitivity Case

Trimble County 2 - 732 MW Supercritical Pulverized Coal
Supercritical Pulverized Coal – 750 MW
Supercritical Pulverized Coal, High Sulfur – 750 MW
Ohio Falls 9 and 10 – 10 MW
Humid Air Turbine Cycle CT – 450 MW
Simple Cycle GE 7FA CT – 148 MW
Combined Cycle 2x1 GE 7FA CT – 484 MW
TDF Multi-Fuel CFB (10% Co-fire) – 50 MW
Wind Energy Conversion – 50 MW
Subcritical Pulverized Coal, High Sulfur – 500 MW

The 11 different technology types and sizes specified between Tables 3 and 4 are those, at first glance, that appear to deserve consideration in detailed computer models. However, this list must be examined further before selecting technologies to pass onto the detailed analysis. As previously stated, there are 891 "opportunities" for each technology to be identified as one of the first three least cost options. Table 4, below, identifies how many occurrences a technology appeared as either first, second, or third least cost options over any capacity factor range. All technologies not identified within Table 4 failed to appear as one of the top three least-cost options in any of the cases identified.

Table 4
The Frequency of Occurrence of Each
Technology as First, Second or Third Least Cost

# Occurences				
1st	**2nd**	**3rd**	**# Occur**	**Technology Name**
135	54	46	235	TC2 732 MW Supercritical Pulverized Coal
162	0	0	162	WV Hydro
0	48	107	155	Supercritical Pulverized Coal - 750 MW
0	82	72	154	Supercritical Pulverized Coal, High Sulfur - 750 MW
0	54	13	67	Ohio Falls 9 and 10
0	27	18	45	Humid Air Turbine Cycle CT - 450 MW
0	27	0	27	Simple Cycle GE 7FA CT - 148 MW
0	0	23	23	Combined Cycle 2x1 GE 7FA CT - 484 MW
0	5	6	11	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW
0	0	8	8	Wind Energy Conversion - 50 MW
0	0	4	4	Subcritical Pulverized Coal, High Sulfur - 500 MW

The WV Hydro option is a power purchase agreement that includes only O&M costs and has no capital costs associated with it. This option was selected as first option 162 times and is the only other option besides the TC2 unit to place first among the least cost options.

The GE 7FA 148 MW simple cycle combustion turbines will be considered for further optimization analysis. Conversion to Combined Cycle appeared as a third place generation alternative 23 times. Prior to any installation of a combined cycle unit, the Companies will be able to evaluate the possibility of conversion of existing simple cycle combustion turbines to combined cycle operation.

As stated previously in this report, the Humid Air Turbine Cycle CT is only in developmental stages and is not commercially available. Therefore, even though it shows up as second and third place among the least cost generation alternatives, this option will not be evaluated further.

Similarly, the tire-derived fuel (TDF) multi-fuel combustion fluidized bed shows up in the second and third place positions among least cost generation alternatives. However, this option will not be evaluated further because of numerous potential difficulties as described previously in part 6 under the Renewable Resource Technology section of this report. Each of these issues (e.g. permitting issues, ash disposal, the negative publicity from fires, etc.) potentially presents a significant stumbling block and in total, prevents TDF from being considered as a viable solution to the Companies' forecasted generation shortfall.

Alternative Analysis with CO_2 Impact

As previously described, a separate analysis was performed to evaluate the impact of a carbon tax on the outcome of the screening analysis. The same sensitivities (inclusion of the impact of SO_2 and NO_x, variability of capital cost, heat rate, and fuel cost) were performed in this analysis as were performed in the preliminary and base case analysis. After implementing carbon comparison of Table 6 and Table 3 from above shows that the technologies remain the same, with the exception of Biomass (Co-Fire) 27.5-MW unit, when a carbon tax of $10 per ton is considered.

Table 6
Second and Third Least-Costly Technologies
In At-Least One Sensitivity Case

Trimble County 2 – 732 MW Supercritical Pulverized Coal
Supercritical Pulverized Coal, High Sulfur – 750 MW
Supercritical Pulverized Coal – 750 MW
Ohio Falls 9 and 10 – 10 MW
Humid Air Turbine Cycle Combustion Turbine – 450 MW
Simple Cycle GE 7FA CT – 148 MW
TDF Multi-Fuel CFB (10% Co-Fire)
Combined Cycle 2x1 GE 7FA CT – 484 MW
Wind Energy Conversion – 50 MW
Subcritical Pulverized Coal, High Sulfur-500 MW
Biomass (Co-Fire) – 27.5 MW

Table 7 identifies how many times a technology appeared as either the first, second or third least-cost option over any capacity factor range and with CO_2 emission tax rates. The analysis with a $10 per ton carbon tax has virtually no impact, with the exception of adding the Biomass (Co-Fire) unit to the technology alternatives. The order and number of occurrences is only slightly changed and the Biomass alternative only occurs once in the third least-costly technology rankings. The scenario where the carbon tax is estimated at $10 per ton is shown in Table 7.

All eleven of the technologies present in the scenario without carbon adders (shown in Table 4) are the same in the scenario with the $10 per ton carbon tax (shown in Table 7), with the addition of the twelfth technology of Biomass (Co-Fire) at 27.5 MW. The only observable changes in the two scenarios involve the number of occurrences and the resulting ranking. Although the number of occurrences changes between the two cases, the changes are not enough to result in significantly rearranging the order of the least cost units. The ordinal ranking remains the same, with the exception of the 50-MW TDF Multi-Fuel CFB (10 percent Co-fire) unit and the 484-MW Combined Cycle unit swapping places for eighth and ninth ranking.

RECOMMENDATIONS

Based on the various analyses discussed above, the technologies listed in Table 8 are recommended for further analysis in the optimization studies using Strategist, a detailed modeling program. The technologies identified will provide a diverse set of alternatives to be evaluated in production and capital costing computer models. Exhibit 9 is a graphical representation of the least-cost technologies, which will be further evaluated in the Strategist optimization software modeling.

Table 8
Technologies Suggested for Analysis
Within Strategist

Trimble County 2 – 732 MW Supercritical Pulverized Coal Unit
Supercritical Pulverized Coal, High Sulfur – 750 MW
WV Hydro – Power Purchase Agreement
Ohio Falls 9 and 10 – Run of River expansion
Simple Cycle GE 7FA CT – 148 MW
Combined Cycle 2x1 GE 7FA CT – 484 MW

Exhibit 1

Technologies Screened

Tech. ID	Technology Description	Category	Sub-Category
6.1	Pumped Hydro Energy Storage - 500 MW	Storage	Hydro
6.2	Lead-Acid Battery Energy Storage - 5 MW	Storage	Battery
6.3	Compressed Air Energy Storage - 500 MW	Storage	Compressed Air
2.1.1	Simple Cycle GE LM6000 CT - 31 MW	Natural Gas	SCCT
2.1.2	Simple Cycle GE 7EA CT - 73 MW	Natural Gas	SCCT
2.1.3	Simple Cycle GE 7FA CT - 148 MW	Natural Gas	SCCT
2.2.1	Combined Cycle GE 7EA CT - 119 MW	Natural Gas	CCCT
2.2.2	Combined Cycle GE 7FA CT - 235 MW	Natural Gas	CCCT
2.2.3	Combined Cycle 2x1 GE 7FA CT - 484 MW	Natural Gas	CCCT
2.1.4	W 501F CC CT - 258 MW	Natural Gas	CCCT
2.5.1	Spark Ignition Engine - 5 MW	Natural Gas	Reciprocating Engine
2.5.2	Compression Ignition Engine - 10 MW	Natural Gas	Reciprocating Engine
3.1.1	Wind Energy Conversion - 50 MW	Renewable	Wind
3.2.1	Solar Thermal, Parabolic Trough - 100 MW	Renewable	Solar
3.2.2	Solar Thermal, Parabolic Dish - 1.2 MW	Renewable	Solar
3.2.3	Solar Thermal, Central Receiver - 50 MW	Renewable	Solar
3.2.4	Solar Thermal, Solar Chimney - 200 MW	Renewable	Solar
3.3	Solar Photovoltaic - 50 kW	Renewable	Solar
3.4.1	Biomass (Co-Fire) - 27.5MW	Renewable	BioMass
3.5	Geothermal - 30 MW	Renewable	Geotherm
3.6	Hydroelectric - New - 30 MW	Renewable	Hydro
102	WV Hydro	Renewable	Hydro
4.1	MSW Mass Burn - 7 MW	Waste To Energy	MSW
4.2	RDF Stoker-Fired - 7 MW	Waste To Energy	RDF
4.3	Landfill Gas IC Engine - 5 MW	Waste To Energy	LFG
4.4	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Waste To Energy	TDF
4.5	Sewage Sludge & Anaerobic Digestion - .085 MW	Waste To Energy	SS
5.1.1	Humid Air Turbine Cycle CT - 450 MW	Natural Gas	CT
5.1.2	Kalina Cycle CC CT - 275 MW	Natural Gas	CCCT
5.1.3	Cheng Cycle CT - 140 MW	Natural Gas	CCCT
5.2.1	Pressurized Fluidized Bed Combustion - 250 MW	Coal	Fluidized Bed Combustion
5.3.1	IGCC - 267 MW	Coal Gasification	IGCC
5.3.2	IGCC - 534 MW	Coal Gasification	IGCC
5.4	Fuel Cell - 0.2 MW	Storage	Fuel Cell
5.5.1	Peaking Microturbine - 0.03 MW	Natural Gas	CT
5.5.2	Baseload Microturbine - 0.03 MW	Natural Gas	CT
2.3.1	Supercritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.2	Supercritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.3	Supercritical Pulverized Coal - 750 MW	Coal	Pulverized Coal
2.3.4	Subcritical Pulverized Coal - 250 MW	Coal	Pulverized Coal
2.3.5	Subcritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.6	Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.7	Supercritical Pulverized Coal, High Sulfur - 750 MW	Coal	Pulverized Coal
2.4.1	Circulating Fluidized Bed - 250 MW	Coal	Fluidized Bed Combustion
2.4.2	Circulating Fluidized Bed - 500 MW	Coal	Fluidized Bed Combustion
100	Ohio Falls 9 and 10	Renewable	Hydro
101	TC2 732 MW Supercritical Pulverized Coal	Coal	Pulverized Coal

CONFIDENTIAL INFORMATION

Exhibit 2(b)

Calculation of SO_2 Adder (Cents/MBtu)

(Post FGD:Assume 95% Removal Eff)

#SO_2/MBTU ----> 0.310 | 0.055 | 0.115

	SO_2 \$/ton Esc @ VO&M	High SO_2		Low SO_2		Med SO_2	
		Base Cost	SO_2 Adder	Base Cost	SO_2 Adder	Base Cost	SO_2 Adder
2004	172	[redacted]	3	[redacted]	0	[redacted]	1
2005	392	[redacted]	6	[redacted]	1	[redacted]	2
2006	405	[redacted]	6	[redacted]	1	[redacted]	2
2007	412	[redacted]	6	[redacted]	1	[redacted]	2
2008	419	[redacted]	6	[redacted]	1	[redacted]	2
2009	407	[redacted]	6	[redacted]	1	[redacted]	2
2010	536	[redacted]	8	[redacted]	1	[redacted]	3
2011	547	[redacted]	8	[redacted]	2	[redacted]	3
2012	558	[redacted]	9	[redacted]	2	[redacted]	3
2013	569	[redacted]	9	[redacted]	2	[redacted]	3
2014	580	[redacted]	9	[redacted]	2	[redacted]	3
2015	592	[redacted]	9	[redacted]	2	[redacted]	3
2016	604	[redacted]	9	[redacted]	2	[redacted]	3
2017	616	[redacted]	10	[redacted]	2	[redacted]	4
2018	628	[redacted]	10	[redacted]	2	[redacted]	4
2019	641	[redacted]	10	[redacted]	2	[redacted]	4
2020	653	[redacted]	10	[redacted]	2	[redacted]	4
2021	666	[redacted]	10	[redacted]	2	[redacted]	4
2022	680	[redacted]	11	[redacted]	2	[redacted]	4
2023	693	[redacted]	11	[redacted]	2	[redacted]	4
2024	707	[redacted]	11	[redacted]	2	[redacted]	4
[illegible]25	721	[redacted]	11	[redacted]	2	[redacted]	4
[illegible]26	736	[redacted]	11	[redacted]	2	[redacted]	4
2027	751	[redacted]	12	[redacted]	2	[redacted]	4
2028	766	[redacted]	12	[redacted]	2	[redacted]	4
2029	781	[redacted]	12	[redacted]	2	[redacted]	4
2030	796	[redacted]	12	[redacted]	2	[redacted]	5
2031	812	[redacted]	13	[redacted]	2	[redacted]	5
2032	829	[redacted]	13	[redacted]	2	[redacted]	5
2033	845	[redacted]	13	[redacted]	2	[redacted]	5

Example calculation of SO_2 adder:

Using High Sulfur Coal = 6.2#SO_2/MBtu

2004 SO_2 \$/Ton = \$172

Scrubber Removal Efficiency = 95% (for each coal burning technology)

2004 High Sulfur SO_2 Cost Adder $= \frac{6.2\#SO_2}{\text{MBtu}} * (1-0.95) * \frac{172\ \$}{\text{Ton } SO_2} * \frac{100\ \text{Cents}}{\$} * \frac{1\ \text{ton } SO_2}{2000\ \#}$

2004 High Sulfur SO_2 Cost Adder = 2.7 cents/MBtu

Calculation of NOx Adder ($/MWh)

Trimble County 2 732 MW Supercritical Coal-fired Unit Data

Uncontrolled NOx Emission Rate:	0.25 lb/MBtu
Controlled NOx Emission Rate:	0.07 lb/MBtu
Base Heat Rate:	8,900 Btu/kWh
2005 NOx Allowance Cost:	$3,125 /ton

NOx lbs/MWh = Controlled Emission Rate x Heat Rate = $\frac{0.07 \text{ lb}}{\text{MBtu}} \times \frac{\text{MBtu}}{1{,}000{,}000 \text{ Btu}} \times \frac{8{,}900 \text{ Btu}}{\text{kWh}} \times \frac{1{,}000 \text{ kWh}}{\text{MWh}}$

= 0.623 lbs/MWh

V O&M Adder = NOx lbs/MWh x 2005 NOx Allowance Cost

$= \frac{0.623 \text{ lbs}}{\text{MWh}} \times \frac{\$3125}{\text{ton}} \times \frac{\text{ton}}{2000 \text{ lbs}} =$ $0.98/MWh

Exhibit 4

LEVELIZATION EQUATIONS USED IN TECHNOLOGY SCREENING

The total levelized cost of a particular technology in a specific year at a specific capacity factor is comprised of (at most) five separate components. The five possible components are levelized capital cost, levelized fixed cost, levelized variable cost, levelized fuel cost and levelized charging cost. The actual components utilized in calculating total levelized cost vary from technology to technology. For example, some technologies may exclude the charging component while others exclude the fuel component. Basically, technologies fall into four categories: Those that...

I. Burn fuel only (i.e. Pulverized Coal, Gas Turbine)
II. Burn no fuel and utilize no "grid" energy (i.e. Solar, Wind)
III. Burn no fuel but utilize "grid" energy for charging (i.e. Battery, Pumped Hydro)
IV. Burn fuel during generation <u>and</u> utilize "grid" energy for charging (i.e. CAES)

A levelization factor (L_n) converts a series of payments that are made over "n" periods and subject to a constant apparent escalation rate into an equivalent levelized payment stream and is calculated as follows:

$$L_n = \frac{k\,(1-k^n)}{a_n\,(1-k)}$$

n = number of years = 30

$$k = \frac{1+e_a}{1+i}$$

e_a = apparent esc rate including inflation and real escalation (i.e., VO&M = 2.0%). See Exhibit 5.

$$a_n = \frac{(1+i)^n - 1}{i\,(1+i)^n}$$

i = Discount Rate = Present Value Rate = 7.14%

$$\text{Adj } L_n = L_n/(1+e_a)$$

The screening analysis utilizes the Adj. L_n. The Adj. L_n makes adjustments for beginning/ending year dollars to be consistent with the Companies' economic analysis methods. An Adj. L_n is calculated for the fixed, variable, fuel and charging costs only. The capital cost component does not utilize an Adj. L_n for levelization because it is levelized through a Fixed Charge Rate (FCR)

Definition of Variables:

Variable		Definition (Units)	Source
Year	=	Levelized Year - Base Year	Exhibit 5
Inst Cost	=	Installed Cost or Total Generic Unit Cost ($/kW)	Exhibit 3
FCR%	=	Fixed Charge Rate (%)	Exhibit 5
Cap Esc%	=	Capital Escalation Rate (%)	Exhibit 5
FO&M	=	Fixed O&M ($/kW)	Exhibit 3
VO&M	=	Variable O&M ($/MWh)	Exhibit 3
Fix Esc	=	Fixed O&M Escalation Rate (%)	Exhibit 5
Var Esc	=	Variable O&M Escalation Rate (%)	Exhibit 5
Fix Adj L_n	=	Fixed O&M Levelization Factor	Exhibit 5
Var Adj L_n	=	Variable O&M Levelization Factor	Exhibit 5
Fuel Adj L_n	=	Fuel Cost Levelization Factor	Base Fuel Only; Exhibit 5
Charge Adj L_n	=	Charging Cost Levelization Factor	Exhibit 5
CF%	=	Capacity Factor (%)	0-100 %
MW	=	Size of Technology (MW)	Exhibit 3
HR	=	Heat Rate (Btu/KWh)	Exhibit 3
FC	=	Fuel Cost ($/MBtu)	Exhibit 2 (a)
Avg Ld IO	=	Average Load (kWh In/kWh Out)	Exhibit 3
Charge	=	Charging Cost ($/MWh)	Exhibit 5
SO_2	=	SO_2 Adder (Cents/MBtu)	Exhibit 2(b)
NO_x	=	NO_x Adder ($/MWh)	Exhibit 2(d)

Adjusted L_n and Other Miscellaneous Data

(All Fuel prices are in Cents/MBtu)

18.19	Base Yr ($/MWh) charging cost
2.00%	Charging Esc.

Year	2.00% Cumulative F O&M Esc	2.00% Cumulative V O&M Esc	2.00% Cumulative Capital Esc	High SO2 6.2#	Gas	Cost Charging	No Fuel	Low SO2 1.15#	Med SO2 2.3#
2004	1.000	1.000	1.000	[redacted]					
2005	1.020	1.020	1.020	[redacted]					
2006	1.040	1.040	1.040	[redacted]					
2007	1.061	1.061	1.061	[redacted]					
2008	1.082	1.082	1.082	[redacted]					
2009	1.104	1.104	1.104	[redacted]					
2010	1.126	1.126	1.126	[redacted]					
2011	1.149	1.149	1.149	[redacted]					
2012	1.172	1.172	1.172	[redacted]					
2013	1.195	1.195	1.195	[redacted]					
2014	1.219	1.219	1.219	[redacted]					
2015	1.243	1.243	1.243	[redacted]					
2016	1.268	1.268	1.268	[redacted]					
2017	1.294	1.294	1.294	[redacted]					
2018	1.319	1.319	1.319	[redacted]					
2019	1.346	1.346	1.346	[redacted]					
2020	1.373	1.373	1.373	[redacted]					
2021	1.400	1.400	1.400	[redacted]					
2022	1.428	1.428	1.428	[redacted]					
2023	1.457	1.457	1.457	[redacted]					
2024	1.486	1.486	1.486	[redacted]					
2025	1.516	1.516	1.516	[redacted]					
2026	1.546	1.546	1.546	[redacted]					
2027	1.577	1.577	1.577	[redacted]					
2028	1.608	1.608	1.608	[redacted]					
2029	1.641	1.641	1.641	[redacted]					
2030	1.673	1.673	1.673	[redacted]					
2031	1.707	1.707	1.707	[redacted]					
2032	1.741	1.741	1.741	[redacted]					
2033	1.776	1.776	1.776	[redacted]					

Fuel Notes:
When utilized, SO_2 cost adder to High SO2, Low SO2 and Med SO2 Coal assumes 95% FGD removal efficiency.
When utilized, the fuel cost adder representing Carbon Tax was applied to High, Low, & Med Sulfur coals, and Natural Gas.
6/29/04 Fuel Forecast Used. All fuel prices in cents per million Btu with the exception of charging which is in $/MWh.
Charging cost base upon average cost of off-peak generation.

		Fixed	*Variable*	*Capital*	High SO2	Gas	Charging	No Fuel	Low SO2	Med SO2
Base Year =	2004									
Levelized Year =	2004									
Ea =		2.00%	2.00%	2.00%	[redacted]					
PV Rate (i) =	7.14%									
k =		0.9520	0.9520	0.9520	[redacted]					
n =	30									
An =	12.2385									
L_n =		1.251	1.251	1.251	[redacted]					
Adj L_n =		1.226	1.226	1.226	[redacted]					

Input
Not an Input
Calculated
Change "Levelized Year" to year desired for "Snapshot" year analysis.
Change "n" to 1 for "Snapshot" year analysis and 30 for levelized analyis.

Fixed Charge Rates by Technology

Coal	9.09%
Simple Cycle CT	10.52%
Combined Cycle CT	9.19%
Other	9.46%
Modification	10.48%

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	152	203	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	225	293	361	429	497	565	633	701	769	837
Simple Cycle GE 7EA CT - 73 MW	108	192	277	362	447	531	616	701	785	870	955
Simple Cycle GE 7FA CT - 148 MW	81	165	248	332	416	500	584	667	751	835	919
Combined Cycle GE 7EA CT - 119 MW	145	198	251	304	357	409	462	515	568	621	674
Combined Cycle GE 7FA CT - 235 MW	116	164	212	261	309	357	405	453	502	550	598
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	144	192	240	288	335	383	431	479	527	575
W 501F CC CT - 258 MW	109	159	208	258	308	358	408	457	507	557	607
Spark Ignition Engine - 5 MW	141	228	316	403	491	578	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	176	254	329	405	480	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1028	1108	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	264	309	353	398	443	488	532	577	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	135	178	222	266	309	353	397	—	—	—
Kalina Cycle CC CT - 275 MW	114	159	204	249	294	339	384	429	—	—	—
Cheng Cycle CT - 140 MW	140	196	252	308	364	421	477	533	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	271	329	387	445	503	561	619	—	—	—
IGCC - 267 MW	237	269	301	333	364	396	428	460	492	—	—
IGCC - 534 MW	207	239	270	302	333	365	396	427	459	—	—
Fuel Cell - 0.2 MW	1394	1453	1512	1572	1631	1691	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	217	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	213	304	395	486	577	668	759	—	—	—
Supercritical Pulverized Coal - 500 MW	167	189	211	233	255	277	299	321	343	364	386
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	196	215	234	253	272	291	310	328	347	366
Supercritical Pulverized Coal - 750 MW	150	172	193	215	236	258	279	301	322	344	365
Subcritical Pulverized Coal - 250 MW	206	228	251	274	297	320	342	365	388	411	434
Subcritical Pulverized Coal - 500 MW	163	185	208	230	252	274	296	319	341	363	385
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	192	211	230	250	269	288	307	326	346	365
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	178	196	215	234	252	271	289	308	327	345
Circulating Fluidized Bed - 250 MW	215	238	262	285	308	331	355	378	401	425	448
Circulating Fluidized Bed - 500 MW	164	186	209	232	255	278	301	324	347	370	393
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	144	159	174	190	205	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	220	235	250	266	281

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low *2004 Dollars ($/kW yr)*
Heat Rate-Low
Fuel Forecast- Base

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	143	193	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	213	277	342	407	472	537	601	666	731	796
Simple Cycle GE 7EA CT - 73 MW	102	183	263	344	425	506	587	667	748	829	910
Simple Cycle GE 7FA CT - 148 MW	77	157	238	318	398	479	559	640	720	800	881
Combined Cycle GE 7EA CT - 119 MW	136	186	237	287	338	388	439	489	540	590	641
Combined Cycle GE 7FA CT - 235 MW	108	154	200	246	292	338	384	430	476	522	568
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	136	181	227	273	318	364	410	456	501	547
W 501F CC CT - 258 MW	102	149	197	244	292	339	387	434	482	529	577
Spark Ignition Engine - 5 MW	127	211	295	380	464	548	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	165	238	311	384	457	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	219	263	306	349	392	436	479	522	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
mid Air Turbine Cycle CT - 450 MW	80	122	163	205	247	288	330	372	—	—	—
lina Cycle CC CT - 275 MW	98	141	184	227	270	312	355	398	—	—	—
Cheng Cycle CT - 140 MW	119	172	226	280	333	387	440	494	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	232	287	343	398	454	509	565	—	—	—
IGCC - 267 MW	201	231	262	293	323	354	384	415	446	—	—
IGCC - 534 MW	173	204	234	264	294	324	354	384	414	—	—
Fuel Cell - 0.2 MW	1263	1319	1376	1433	1490	1547	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	188	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	184	272	359	446	533	621	708	—	—	—
Supercritical Pulverized Coal - 500 MW	153	174	195	216	237	258	279	300	321	341	362
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	181	199	218	236	254	272	290	308	326	344
Supercritical Pulverized Coal - 750 MW	137	158	178	199	219	240	260	281	301	322	342
Subcritical Pulverized Coal - 250 MW	189	210	232	254	276	298	319	341	363	385	407
Subcritical Pulverized Coal - 500 MW	149	170	192	213	234	255	276	298	319	340	361
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	177	195	214	232	250	269	287	305	324	342
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	164	182	200	218	236	254	272	289	307	325
Circulating Fluidized Bed - 250 MW	197	219	242	264	286	308	331	353	375	398	420
Circulating Fluidized Bed - 500 MW	150	171	193	215	237	259	280	302	324	346	368
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	131	146	160	175	189	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	204	218	233	247	262

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast-Low

					Capacity Factors						
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	142	190	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	209	271	333	394	456	517	579	641	702	764
Simple Cycle GE 7EA CT - 73 MW	102	179	256	332	409	486	563	640	717	794	871
Simple Cycle GE 7FA CT - 148 MW	77	154	231	308	384	461	538	615	692	769	846
Combined Cycle GE 7EA CT - 119 MW	136	184	232	280	328	376	424	472	520	568	616
Combined Cycle GE 7FA CT - 235 MW	108	152	196	239	283	327	371	415	458	502	546
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	134	177	221	264	308	352	395	439	482	526
W 501F CC CT - 258 MW	102	147	192	237	283	328	373	418	463	509	554
Spark Ignition Engine - 5 MW	127	208	289	371	452	533	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	163	233	304	374	445	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	·383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	218	260	302	344	385	427	469	511	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
'umid Air Turbine Cycle CT - 450 MW	80	119	159	199	238	278	317	357	—	—	—
ina Cycle CC CT - 275 MW	98	139	180	220	261	302	342	383	—	—	—
neng Cycle CT - 140 MW	119	170	221	271	322	373	424	475	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	229	282	335	387	440	493	546	—	—	—
IGCC - 267 MW	201	230	260	289	319	348	377	407	436	—	—
IGCC - 534 MW	173	202	231	260	289	318	347	376	405	—	—
Fuel Cell - 0.2 MW	1263	1317	1371	1426	1480	1535	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	184	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	181	264	348	431	515	598	682	—	—	—
Supercritical Pulverized Coal - 500 MW	153	172	191	209	228	246	265	284	302	321	339
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	182	200	218	237	255	274	292	310	329	347
Supercritical Pulverized Coal - 750 MW	137	156	174	192	211	229	247	266	284	302	320
Subcritical Pulverized Coal - 250 MW	189	208	227	247	266	286	305	324	344	363	383
Subcritical Pulverized Coal - 500 MW	149	168	187	206	224	243	262	281	300	318	337
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	177	196	215	233	252	270	289	308	326	345
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	164	182	201	219	237	255	273	291	309	327
Circulating Fluidized Bed - 250 MW	197	217	237	257	277	296	316	336	356	376	396
Circulating Fluidized Bed - 500 MW	150	169	189	208	228	247	267	286	306	325	345
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	131	146	161	175	190	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	204	219	234	248	263

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	147	201	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	222	297	371	446	520	595	669	744	818	893
Simple Cycle GE 7EA CT - 73 MW	102	194	287	379	471	564	656	749	841	933	1026
Simple Cycle GE 7FA CT - 148 MW	77	168	258	349	440	531	622	712	803	894	985
Combined Cycle GE 7EA CT - 119 MW	136	194	251	309	367	424	482	540	598	655	713
Combined Cycle GE 7FA CT - 235 MW	108	161	213	266	318	371	424	476	529	581	634
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	142	195	247	299	351	404	456	508	561	613
W 501F CC CT - 258 MW	102	156	211	265	319	374	428	483	537	591	646
Spark Ignition Engine - 5 MW	127	220	314	407	501	594	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	172	253	333	414	494	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	224	271	319	366	414	461	509	556	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	128	175	223	271	318	366	414	—	—	—
Kalina Cycle CC CT - 275 MW	98	147	196	246	295	344	393	442	—	—	—
Cheng Cycle CT - 140 MW	119	180	242	303	365	426	487	549	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	240	303	366	430	493	556	620	—	—	—
IGCC - 267 MW	201	235	270	304	339	373	408	442	477	—	—
IGCC - 534 MW	173	207	241	275	309	343	377	411	445	—	—
Fuel Cell - 0.2 MW	1263	1327	1392	1456	1521	1586	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	200	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	195	294	392	491	589	688	786	—	—	—
Supercritical Pulverized Coal - 500 MW	153	177	201	224	248	272	296	319	343	367	390
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	185	207	229	251	273	295	317	338	360	382
Supercritical Pulverized Coal - 750 MW	137	161	184	207	230	253	277	300	323	346	369
Subcritical Pulverized Coal - 250 MW	189	213	238	262	287	312	336	361	385	410	435
Subcritical Pulverized Coal - 500 MW	149	173	197	221	245	269	293	317	341	365	389
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	181	203	225	248	270	292	314	336	359	381
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	168	189	211	232	254	275	297	318	340	361
Circulating Fluidized Bed - 250 MW	197	222	247	273	298	323	348	373	399	424	449
Circulating Fluidized Bed - 500 MW	150	174	199	224	248	273	298	322	347	372	397
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	135	153	170	188	206	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	224	242	260	278	296

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost-Low — **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	145	197	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	219	290	362	433	504	576	647	718	789	861
Simple Cycle GE 7EA CT - 73 MW	102	190	279	368	456	545	633	722	811	899	988
Simple Cycle GE 7FA CT - 148 MW	77	164	251	339	426	513	601	688	775	863	950
Combined Cycle GE 7EA CT - 119 MW	136	191	247	302	357	412	468	523	578	634	689
Combined Cycle GE 7FA CT - 235 MW	108	158	209	259	310	360	410	461	511	562	612
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	140	190	240	290	340	391	441	491	541	591
W 501F CC CT - 258 MW	102	154	206	258	310	362	414	467	519	571	623
Spark Ignition Engine - 5 MW	127	217	308	398	489	579	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	170	248	325	403	481	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, *Solar Chimney - 200 MW*	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	222	268	314	361	407	453	499	545	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	126	171	217	263	308	354	400	—	—	—
Kalina Cycle CC CT - 275 MW	98	145	192	239	286	333	380	427	—	—	—
Cheng Cycle CT - 140 MW	119	178	237	295	354	413	472	531	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	237	298	359	419	480	541	602	—	—	—
IGCC - 267 MW	201	234	267	300	334	367	400	433	466	—	—
IGCC - 534 MW	173	206	239	272	304	337	370	402	435	—	—
Fuel Cell - 0.2 MW	1263	1325	1387	1449	1511	1573	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	196	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	192	286	381	476	571	665	760	—	—	—
Supercritical Pulverized Coal - 500 MW	153	176	199	222	245	268	291	314	337	359	382
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	183	203	222	242	262	281	301	321	341	360
Supercritical Pulverized Coal - 750 MW	137	160	182	205	227	250	272	295	317	340	362
Subcritical Pulverized Coal - 250 MW	189	212	236	260	284	308	331	355	379	403	427
Subcritical Pulverized Coal - 500 MW	149	172	196	219	242	265	288	312	335	358	381
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	179	199	219	238	258	278	298	318	338	358
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	166	185	204	223	243	262	281	301	320	339
Circulating Fluidized Bed - 250 MW	197	221	246	270	295	319	343	368	392	417	441
Circulating Fluidized Bed - 500 MW	150	173	197	221	245	269	293	317	341	365	389
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	133	149	164	180	196	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	212	228	244	260	276

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	148	196	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	215	274	333	392	450	509	568	626	685	744
Simple Cycle GE 7EA CT - 73 MW	108	181	255	328	401	475	548	622	695	768	842
Simple Cycle GE 7FA CT - 148 MW	81	155	228	302	376	450	524	597	671	745	819
Combined Cycle GE 7EA CT - 119 MW	145	191	237	283	329	374	420	466	512	558	604
Combined Cycle GE 7FA CT - 235 MW	116	158	200	241	283	325	367	409	450	492	534
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	138	179	221	262	304	346	387	429	470	512
W 501F CC CT - 258 MW	109	152	195	238	281	324	367	411	454	497	540
Spark Ignition Engine - 5 MW	141	220	298	377	455	534	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	171	240	308	377	445	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	260	300	341	381	422	462	503	543	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	129	167	204	242	280	318	356	—	—	—
:alina Cycle CC CT - 275 MW	114	153	192	231	270	308	347	386	—	—	—
Cheng Cycle CT - 140 MW	140	188	237	285	334	382	430	479	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	263	313	363	414	464	514	565	—	—	—
IGCC - 267 MW	237	265	293	322	350	378	406	435	463	—	—
IGCC - 534 MW	207	235	263	291	319	346	374	402	430	—	—
Fuel Cell - 0.2 MW	1394	1446	1498	1550	1602	1654	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	206	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	202	282	362	443	523	603	683	—	—	—
Supercritical Pulverized Coal - 500 MW	167	185	203	220	238	256	274	291	309	327	344
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	195	212	230	248	265	283	300	318	336	353
Supercritical Pulverized Coal - 750 MW	150	168	185	203	220	237	255	272	290	307	324
Subcritical Pulverized Coal - 250 MW	206	224	243	261	280	298	317	335	354	372	391
Subcritical Pulverized Coal - 500 MW	163	181	199	217	235	253	271	289	307	325	343
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	191	208	226	244	262	280	297	315	333	351
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	177	194	211	229	246	264	281	298	316	333
Circulating Fluidized Bed - 250 MW	215	234	253	272	291	310	329	348	367	386	405
Circulating Fluidized Bed - 500 MW	164	182	201	219	238	257	275	294	312	331	350
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	143	157	171	185	199	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	213	227	241	255	269

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast- High

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	153	205	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	228	299	369	440	511	582	653	724	795	866
Simple Cycle GE 7EA CT - 73 MW	108	196	284	372	461	549	637	725	813	902	990
Simple Cycle GE 7FA CT - 148 MW	81	168	255	342	429	516	603	690	777	864	951
Combined Cycle GE 7EA CT - 119 MW	145	200	255	310	365	420	476	531	586	641	696
Combined Cycle GE 7FA CT - 235 MW	116	166	216	266	316	367	417	467	517	567	617
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	146	196	246	296	345	395	445	495	545	595
W 501F CC CT - 258 MW	109	161	212	264	316	368	420	471	523	575	627
Spark Ignition Engine - 5 MW	141	231	321	411	501	591	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	181	258	336	413	491	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	265	311	357	403	449	495	541	587	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
lumid Air Turbine Cycle CT - 450 MW	91	136	182	228	273	319	364	410	—	—	—
.alina Cycle CC CT - 275 MW	114	161	208	255	302	348	395	442	—	—	—
Cheng Cycle CT - 140 MW	140	198	257	316	374	433	491	550	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	273	333	394	454	515	575	636	—	—	—
IGCC - 267 MW	237	270	303	336	369	402	435	468	501	—	—
IGCC - 534 MW	207	240	273	305	338	370	403	436	468	—	—
Fuel Cell - 0.2 MW	1394	1455	1517	1579	1641	1703	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	221	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	216	311	405	500	594	689	783	—	—	—
Supercritical Pulverized Coal - 500 MW	167	190	212	235	257	280	302	325	347	370	392
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	198	219	240	261	282	303	324	344	365	386
Supercritical Pulverized Coal - 750 MW	150	173	195	217	239	261	283	305	327	349	371
Subcritical Pulverized Coal - 250 MW	206	229	253	276	300	323	347	370	394	417	441
Subcritical Pulverized Coal - 500 MW	163	186	209	232	255	278	301	323	346	369	392
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	194	215	236	258	279	300	321	342	364	385
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	180	200	221	242	262	283	303	324	345	365
Circulating Fluidized Bed - 250 MW	215	239	263	287	311	335	360	384	408	432	456
Circulating Fluidized Bed - 500 MW	164	187	211	234	258	281	305	328	352	375	399
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	146	163	180	197	214	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	231	248	266	283	300

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast- High

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
						Capacity Factors					
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	155	209	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	231	306	380	455	529	604	678	753	827	902
Simple Cycle GE 7EA CT - 73 MW	108	200	293	385	477	570	662	755	847	939	1032
Simple Cycle GE 7FA CT - 148 MW	81	172	262	353	444	535	626	716	807	898	989
Combined Cycle GE 7EA CT - 119 MW	145	203	260	318	376	433	491	549	607	664	722
Combined Cycle GE 7FA CT - 235 MW	116	169	221	274	326	379	432	484	537	589	642
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	148	201	253	305	357	410	462	514	567	619
W 501F CC CT - 258 MW	109	163	218	272	326	381	435	490	544	598	653
Spark Ignition Engine - 5 MW	141	234	328	421	515	608	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	183	264	344	425	505	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	267	314	362	409	457	504	552	599	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	139	186	234	282	329	377	425	—	—	—
Kalina Cycle CC CT - 275 MW	114	163	212	262	311	360	409	458	—	—	—
Cheng Cycle CT - 140 MW	140	201	263	324	386	447	508	570	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	276	339	402	466	529	592	656	—	—	—
IGCC - 267 MW	237	271	306	340	375	409	444	478	513	—	—
IGCC - 534 MW	207	241	275	309	343	377	411	445	479	—	—
Fuel Cell - 0.2 MW	1394	1458	1523	1587	1652	1717	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	225	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	220	319	417	516	614	713	811	—	—	—
Supercritical Pulverized Coal - 500 MW	167	191	215	238	262	286	310	333	357	381	404
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	199	221	243	265	287	309	331	352	374	396
Supercritical Pulverized Coal - 750 MW	150	174	197	220	243	266	290	313	336	359	382
Subcritical Pulverized Coal - 250 MW	206	230	255	279	304	329	353	378	402	427	452
Subcritical Pulverized Coal - 500 MW	163	187	211	235	259	283	307	331	355	379	403
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	195	217	239	262	284	306	328	350	373	395
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	181	202	224	245	267	288	310	331	353	374
Circulating Fluidized Bed - 250 MW	215	240	265	291	316	341	366	391	417	442	467
Circulating Fluidized Bed - 500 MW	164	188	213	238	262	287	312	336	361	386	411
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	147	165	182	200	218	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	236	254	272	290	308

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	153	205	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	228	299	371	442	513	585	656	727	798	870
Simple Cycle GE 7EA CT - 73 MW	108	196	285	374	462	551	639	728	817	905	994
Simple Cycle GE 7FA CT - 148 MW	81	168	255	343	430	517	605	692	779	867	954
Combined Cycle GE 7EA CT - 119 MW	145	200	256	311	366	421	477	532	587	643	698
Combined Cycle GE 7FA CT - 235 MW	116	166	217	267	318	368	418	469	519	570	620
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	146	196	246	296	346	397	447	497	547	597
W 501F CC CT - 258 MW	109	161	213	265	317	369	421	474	526	578	630
Spark Ignition Engine - 5 MW	141	231	322	412	503	593	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	181	259	336	414	492	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	265	311	357	404	450	496	542	588	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	137	182	228	274	319	365	411	—	—	—
Kalina Cycle CC CT - 275 MW	114	161	208	255	302	349	396	443	—	—	—
Cheng Cycle CT - 140 MW	140	199	258	316	375	434	493	552	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	273	334	395	455	516	577	638	—	—	—
IGCC - 267 MW	237	270	303	336	370	403	436	469	502	—	—
IGCC - 534 MW	207	240	273	306	338	371	404	436	469	—	—
Fuel Cell - 0.2 MW	1394	1456	1518	1580	1642	1704	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	221	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	217	311	406	501	596	690	785	—	—	—
Supercritical Pulverized Coal - 500 MW	167	190	213	236	259	282	305	328	351	373	396
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	197	217	236	256	276	295	315	335	355	374
Supercritical Pulverized Coal - 750 MW	150	173	195	218	240	263	285	308	330	353	375
Subcritical Pulverized Coal - 250 MW	206	229	253	277	301	325	348	372	396	420	444
Subcritical Pulverized Coal - 500 MW	163	186	210	233	256	279	302	326	349	372	395
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	193	213	233	252	272	292	312	332	352	372
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	179	198	217	236	256	275	294	314	333	352
Circulating Fluidized Bed - 250 MW	215	239	264	288	313	337	361	386	410	435	459
Circulating Fluidized Bed - 500 MW	164	187	211	235	259	283	307	331	355	379	403
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	145	161	176	192	208	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	224	240	256	272	288

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High — **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	164	212	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	166	224	283	342	401	459	518	577	635	694	753
Simple Cycle GE 7EA CT - 73 MW	114	187	261	334	407	481	554	628	701	774	848
Simple Cycle GE 7FA CT - 148 MW	86	160	233	307	381	455	529	602	676	750	824
Combined Cycle GE 7EA CT - 119 MW	155	201	247	293	339	384	430	476	522	568	614
Combined Cycle GE 7FA CT - 235 MW	123	165	207	248	290	332	374	416	457	499	541
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	143	184	226	267	309	351	392	434	475	517
W 501F CC CT - 258 MW	116	159	202	245	288	331	374	418	461	504	547
Spark Ignition Engine - 5 MW	155	234	312	391	469	548	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	181	250	318	387	455	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	304	344	385	425	466	506	547	587	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	140	178	215	253	291	329	367	—	—	—
Kalina Cycle CC CT - 275 MW	131	170	209	248	287	325	364	403	—	—	—
Cheng Cycle CT - 140 MW	160	208	257	305	354	402	450	499	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	298	348	398	449	499	549	600	—	—	—
IGCC - 267 MW	273	301	329	358	386	414	442	471	499	—	—
IGCC - 534 MW	240	268	296	324	352	379	407	435	463	—	—
Fuel Cell - 0.2 MW	1526	1578	1630	1682	1734	1786	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	230	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	226	306	386	467	547	627	707	—	—	—
Supercritical Pulverized Coal - 500 MW	181	199	217	234	252	270	288	305	323	341	358
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	210	227	245	263	280	298	315	333	351	368
Supercritical Pulverized Coal - 750 MW	162	180	197	215	232	249	267	284	302	319	336
Subcritical Pulverized Coal - 250 MW	223	241	260	278	297	315	334	352	371	389	408
Subcritical Pulverized Coal - 500 MW	176	194	212	230	248	266	284	302	320	338	356
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	205	222	240	258	276	294	311	329	347	365
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	191	208	225	243	260	278	295	312	330	347
Circulating Fluidized Bed - 250 MW	232	251	270	289	308	327	346	365	384	403	422
Circulating Fluidized Bed - 500 MW	178	196	215	233	252	271	289	308	326	345	364
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	154	168	182	196	210	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	224	238	252	266	280

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High — **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	169	221	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	168	237	308	378	449	520	591	662	733	804	875
Simple Cycle GE 7EA CT - 73 MW	114	202	290	378	467	555	643	731	819	908	996
Simple Cycle GE 7FA CT - 148 MW	86	173	260	347	434	521	608	695	782	869	956
Combined Cycle GE 7EA CT - 119 MW	155	210	265	320	375	430	486	541	596	651	706
Combined Cycle GE 7FA CT - 235 MW	123	173	223	273	323	374	424	474	524	574	624
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	151	201	251	301	350	400	450	500	550	600
W 501F CC CT - 258 MW	116	168	219	271	323	375	427	478	530	582	634
Spark Ignition Engine - 5 MW	155	245	335	425	515	605	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	191	268	346	423	501	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	309	355	401	447	493	539	585	631	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	147	193	239	284	330	375	421	—	—	—
Kalina Cycle CC CT - 275 MW	131	178	225	272	319	365	412	459	—	—	—
Cheng Cycle CT - 140 MW	160	218	277	336	394	453	511	570	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	308	368	429	489	550	610	671	—	—	—
IGCC - 267 MW	273	306	339	372	405	438	471	504	537	—	—
IGCC - 534 MW	240	273	306	338	371	403	436	469	501	—	—
Fuel Cell - 0.2 MW	1526	1587	1649	1711	1773	1835	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	245	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	240	335	429	524	618	713	807	—	—	—
Supercritical Pulverized Coal - 500 MW	181	204	226	249	271	294	316	339	361	384	406
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	213	234	255	276	297	318	339	359	380	401
Supercritical Pulverized Coal - 750 MW	162	185	207	229	251	273	295	317	339	361	383
Subcritical Pulverized Coal - 250 MW	223	246	270	293	317	340	364	387	411	434	458
Subcritical Pulverized Coal - 500 MW	176	199	222	245	268	291	314	336	359	382	405
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	208	229	250	272	293	314	335	356	378	399
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	194	214	235	256	276	297	317	338	359	379
Circulating Fluidized Bed - 250 MW	232	256	280	304	328	352	377	401	425	449	473
Circulating Fluidized Bed - 500 MW	178	201	225	248	272	295	319	342	366	389	413
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	157	174	191	208	225	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	242	259	277	294	311

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast- Base

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
						Capacity Factors					
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	168	219	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	166	234	302	370	438	506	574	642	710	778	846
Simple Cycle GE 7EA CT - 73 MW	114	198	283	368	453	537	622	707	791	876	961
Simple Cycle GE 7FA CT - 148 MW	86	170	253	337	421	505	589	672	756	840	924
Combined Cycle GE 7EA CT - 119 MW	155	208	261	314	367	419	472	525	578	631	684
Combined Cycle GE 7FA CT - 235 MW	123	171	219	268	316	364	412	460	509	557	605
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	149	197	245	293	340	388	436	484	532	580
W 501F CC CT - 258 MW	116	166	215	265	315	365	415	464	514	564	614
Spark Ignition Engine - 5 MW	155	242	330	417	505	592	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	188	264	339	415	490	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	308	353	397	442	487	532	576	621	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	146	189	233	277	320	364	408	—	—	—
Kalina Cycle CC CT - 275 MW	131	176	221	266	311	356	401	446	—	—	—
Cheng Cycle CT - 140 MW	160	216	272	328	384	441	497	553	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	306	364	422	480	538	596	654	—	—	—
IGCC - 267 MW	273	305	337	369	400	432	464	496	528	—	—
IGCC - 534 MW	240	272	303	335	366	398	429	460	492	—	—
Fuel Cell - 0.2 MW	1526	1585	1644	1704	1763	1823	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	241	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	237	328	419	510	601	692	783	—	—	—
Supercritical Pulverized Coal - 500 MW	181	203	225	247	269	291	313	335	357	378	400
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	211	230	249	268	287	306	325	343	362	381
Supercritical Pulverized Coal - 750 MW	162	184	205	227	248	270	291	313	334	356	377
Subcritical Pulverized Coal - 250 MW	223	245	268	291	314	337	359	382	405	428	451
Subcritical Pulverized Coal - 500 MW	176	198	221	243	265	287	309	332	354	376	398
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	206	225	244	264	283	302	321	340	360	379
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	192	210	229	248	266	285	303	322	341	359
Circulating Fluidized Bed - 250 MW	232	255	279	302	325	348	372	395	418	442	465
Circulating Fluidized Bed - 500 MW	178	200	223	246	269	292	315	338	361	384	407
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	155	170	185	201	216	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	231	248	261	277	292

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High — **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	167	217	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	168	230	295	359	424	488	553	617	682	746	811
Simple Cycle GE 7EA CT - 73 MW	114	194	275	355	435	516	596	677	757	837	918
Simple Cycle GE 7FA CT - 148 MW	88	166	248	326	406	486	566	646	726	806	886
Combined Cycle GE 7EA CT - 119 MW	155	205	255	306	356	406	456	506	557	607	657
Combined Cycle GE 7FA CT - 235 MW	123	169	215	260	306	352	398	444	489	535	581
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	146	192	237	283	328	374	419	465	510	556
W 501F CC CT - 258 MW	118	163	210	258	305	352	400	447	494	*542*	*589*
Spark Ignition Engine - 5 MW	155	239	323	407	491	575	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	186	259	331	404	477	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	306	349	392	436	479	522	565	608	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	143	185	226	268	309	350	392	—	—	—
Kalina Cycle CC CT - 275 MW	131	174	217	259	302	345	387	430	—	—	—
Cheng Cycle CT - 140 MW	160	213	266	320	373	426	480	533	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	303	358	413	468	523	578	634	—	—	—
IGCC - 267 MW	273	303	334	364	395	425	456	486	517	—	—
IGCC - 534 MW	240	270	300	330	360	390	420	450	480	—	—
Fuel Cell - 0.2 MW	1526	1582	1639	1695	1752	1809	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	237	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	233	320	407	493	580	667	754	—	—	—
Supercritical Pulverized Coal - 500 MW	181	201	220	240	259	278	298	317	337	356	375
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	211	230	250	269	288	307	326	345	364	383
Supercritical Pulverized Coal - 750 MW	162	182	201	220	239	258	277	296	315	334	353
Subcritical Pulverized Coal - 250 MW	223	243	263	283	303	324	344	364	384	404	425
Subcritical Pulverized Coal - 500 MW	176	196	216	235	255	275	294	314	334	353	373
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	206	225	245	264	283	303	322	341	361	380
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	192	211	229	248	267	285	304	323	342	360
Circulating Fluidized Bed - 250 MW	232	253	274	294	315	336	357	378	398	419	440
Circulating Fluidized Bed - 500 MW	178	198	218	238	259	279	299	320	340	360	381
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	155	170	186	201	216	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	232	247	262	277	293

Exhibit 6

Levelized Dollars at Various Capacity Factors With SO2 Adders, without CO2 Adders, and with NOx Adders

Capital Cost- High — **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	172	227	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	166	244	322	400	478	556	634	712	790	868	946
Simple Cycle GE 7EA CT - 73 MW	114	210	307	404	501	597	694	791	887	984	1081
Simple Cycle GE 7FA CT - 148 MW	86	180	275	370	464	559	653	748	843	937	1032
Combined Cycle GE 7EA CT - 119 MW	155	215	276	336	397	457	517	578	638	699	759
Combined Cycle GE 7FA CT - 235 MW	123	178	233	288	343	398	453	508	563	618	673
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	156	210	265	320	374	429	484	539	593	648
W 501F CC CT - 258 MW	116	173	230	287	343	400	457	514	571	628	685
Spark Ignition Engine - 5 MW	155	252	348	445	541	638	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	196	279	362	445	528	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	312	361	410	460	509	558	607	656	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	152	202	252	302	352	402	452	—	—	—
Kalina Cycle CC CT - 275 MW	131	183	234	285	337	388	440	491	—	—	—
Cheng Cycle CT - 140 MW	160	224	289	353	418	482	546	611	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	314	380	446	513	579	645	712	—	—	—
IGCC - 267 MW	273	309	345	381	416	452	488	524	560	—	—
IGCC - 534 MW	240	276	311	347	382	418	453	488	524	—	—
Fuel Cell - 0.2 MW	1526	1593	1660	1728	1795	1863	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	254	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	249	351	454	556	659	761	864	—	—	—
Supercritical Pulverized Coal - 500 MW	181	206	231	255	280	305	330	354	379	404	428
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	215	238	260	283	306	328	351	374	397	419
Supercritical Pulverized Coal - 750 MW	162	187	211	235	260	284	308	333	357	381	405
Subcritical Pulverized Coal - 250 MW	223	248	274	300	325	351	377	402	428	454	480
Subcritical Pulverized Coal - 500 MW	176	201	226	251	277	302	327	352	377	402	427
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	210	233	256	279	302	325	348	371	394	417
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	196	218	240	262	285	307	329	352	374	396
Circulating Fluidized Bed - 250 MW	232	258	285	311	338	364	390	417	443	470	496
Circulating Fluidized Bed - 500 MW	178	203	229	255	281	307	332	358	384	410	436
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	159	177	196	215	234	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	253	271	290	309	328

Exhibit 8

30-Year Levelized Cost For All Technologies Over All Capacity Factors With CO_2 Emissions

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost-Low — **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast-Low

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	141	189	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	208	268	328	388	448	508	568	629	689	749
Simple Cycle GE 7EA CT - 73 MW	102	177	252	327	402	477	552	627	703	778	853
Simple Cycle GE 7FA CT - 148 MW	77	152	227	303	378	453	529	604	679	755	830
Combined Cycle GE 7EA CT - 119 MW	136	183	230	277	324	370	417	464	511	558	605
Combined Cycle GE 7FA CT - 235 MW	108	151	193	236	279	322	364	407	450	492	535
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	132	175	217	260	302	345	387	430	472	515
W 501F CC CT - 258 MW	102	146	190	234	278	322	366	411	455	499	543
Spark Ignition Engine - 5 MW	127	207	287	366	446	526	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	161	231	300	370	439	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	219	262	305	348	390	433	476	519	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	119	157	196	235	273	312	351	—	—	—
Kalina Cycle CC CT - 275 MW	98	138	178	217	257	297	336	376	—	—	—
Cheng Cycle CT - 140 MW	119	168	218	268	317	367	416	466	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	228	279	331	382	434	485	537	—	—	—
IGCC - 267 MW	201	231	262	292	322	353	383	413	444	—	—
IGCC - 534 MW	173	203	233	263	293	323	353	383	413	—	—
Fuel Cell - 0.2 MW	1263	1316	1369	1422	1475	1528	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	182	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	179	260	342	424	506	587	669	—	—	—
Supercritical Pulverized Coal - 500 MW	153	173	194	214	234	254	274	294	314	334	354
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	183	203	223	243	263	283	303	323	343	363
Supercritical Pulverized Coal - 750 MW	137	157	177	197	216	236	256	275	295	315	334
Subcritical Pulverized Coal - 250 MW	189	210	231	252	273	294	315	336	357	378	399
Subcritical Pulverized Coal - 500 MW	149	170	190	210	231	251	272	292	312	333	353
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	179	199	220	240	260	281	301	321	342	362
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	166	186	205	225	245	264	284	304	324	343
Circulating Fluidized Bed - 250 MW	197	218	240	261	283	304	326	347	369	390	412
Circulating Fluidized Bed - 500 MW	150	171	192	213	234	255	276	297	318	339	360
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	133	149	166	182	198	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	215	231	247	263	280

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost-Low — **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast- High

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	146	198	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	220	292	365	437	509	582	654	726	798	871
Simple Cycle GE 7EA CT - 73 MW	102	192	281	371	461	551	641	730	820	910	1000
Simple Cycle GE 7FA CT - 148 MW	77	165	254	342	430	519	607	696	784	872	961
Combined Cycle GE 7EA CT - 119 MW	136	192	248	304	360	416	473	529	585	641	697
Combined Cycle GE 7FA CT - 235 MW	108	159	210	261	312	364	415	466	517	568	619
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	141	192	242	293	344	395	446	496	547	598
W 501F CC CT - 258 MW	102	155	207	260	313	366	419	471	524	577	630
Spark Ignition Engine - 5 MW	127	218	310	401	493	584	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	171	249	328	406	485	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	224	273	321	370	418	466	515	563	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	126	173	219	266	312	358	405	—	—	—
Kalina Cycle CC CT - 275 MW	98	146	194	241	289	337	384	432	—	—	—
Cheng Cycle CT - 140 MW	119	179	238	298	358	417	477	537	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	238	300	361	423	484	546	608	—	—	—
IGCC - 267 MW	201	236	271	306	342	377	412	447	482	—	—
IGCC - 534 MW	173	208	243	278	312	347	382	416	451	—	—
Fuel Cell - 0.2 MW	1263	1325	1388	1451	1514	1577	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	197	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	193	289	385	481	577	673	769	—	—	—
Supercritical Pulverized Coal - 500 MW	153	178	204	229	254	279	304	329	354	379	404
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	187	210	234	257	281	304	328	351	375	398
Supercritical Pulverized Coal - 750 MW	137	162	187	211	236	260	285	310	334	359	383
Subcritical Pulverized Coal - 250 MW	189	215	241	267	293	320	346	372	398	424	451
Subcritical Pulverized Coal - 500 MW	149	175	200	226	251	277	302	328	353	379	404
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	183	206	230	254	278	302	325	349	373	397
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	169	193	216	239	262	285	309	332	355	378
Circulating Fluidized Bed - 250 MW	197	224	250	277	304	330	357	384	411	437	464
Circulating Fluidized Bed - 500 MW	150	176	202	228	254	280	306	332	358	384	411
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	136	156	176	195	215	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	234	254	274	293	313

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost-Low 2004 Dollars ($/kW yr)
Heat Rate- Base
Fuel Forecast- Base

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	178	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	145	197	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	217	287	356	426	495	565	634	704	773	843
Simple Cycle GE 7EA CT - 73 MW	102	188	275	361	447	534	620	707	793	879	966
Simple Cycle GE 7FA CT - 148 MW	77	162	248	333	418	504	589	675	760	845	931
Combined Cycle GE 7EA CT - 119 MW	136	190	244	298	352	406	460	514	568	622	676
Combined Cycle GE 7FA CT - 235 MW	108	157	206	256	305	354	403	452	502	551	600
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	139	188	237	286	334	383	432	481	530	579
W 501F CC CT - 258 MW	102	153	203	254	305	356	407	457	508	559	610
Spark Ignition Engine - 5 MW	127	216	304	393	481	570	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	169	245	322	398	475	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	223	270	317	365	412	459	506	553	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	124	169	214	258	303	347	392	—	—	—
Kalina Cycle CC CT - 275 MW	98	144	190	236	282	327	373	419	—	—	—
Cheng Cycle CT - 140 MW	119	176	234	291	349	406	463	521	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	236	295	354	414	473	532	592	—	—	—
IGCC - 267 MW	201	235	269	303	337	371	406	440	474	—	—
IGCC - 534 MW	173	207	241	274	308	342	375	409	443	—	—
Fuel Cell - 0.2 MW	1263	1323	1384	1444	1505	1566	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	194	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	190	282	375	468	561	653	746	—	—	—
Supercritical Pulverized Coal - 500 MW	153	178	202	227	251	276	300	325	349	374	398
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	185	206	228	249	271	292	314	335	357	378
Supercritical Pulverized Coal - 750 MW	137	162	186	210	234	258	282	306	330	354	378
Subcritical Pulverized Coal - 250 MW	189	214	240	265	291	316	342	367	393	418	444
Subcritical Pulverized Coal - 500 MW	149	174	199	224	248	273	298	323	348	372	397
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	181	202	224	246	268	290	311	333	355	377
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	167	188	210	231	252	273	294	315	336	357
Circulating Fluidized Bed - 250 MW	197	223	249	275	301	327	353	379	405	431	457
Circulating Fluidized Bed - 500 MW	150	175	201	226	252	277	303	328	354	379	405
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	134	152	170	187	205	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	222	240	258	275	293

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost-Low **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	143	193	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	214	280	346	412	478	544	610	676	742	808
Simple Cycle GE 7EA CT - 73 MW	102	184	266	348	431	513	595	677	759	842	924
Simple Cycle GE 7FA CT - 148 MW	77	159	240	322	404	485	567	649	730	812	894
Combined Cycle GE 7EA CT - 119 MW	136	187	239	290	342	393	444	496	547	599	650
Combined Cycle GE 7FA CT - 235 MW	108	155	202	248	295	342	389	436	482	529	576
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	136	183	229	276	322	369	415	462	508	555
W 501F CC CT - 258 MW	102	150	198	247	295	343	392	440	488	537	585
Spark Ignition Engine - 5 MW	127	212	298	383	469	554	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	166	240	314	388	462	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	222	268	313	359	405	451	496	542	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	122	165	207	250	292	334	377	—	—	—
Kalina Cycle CC CT - 275 MW	98	142	185	229	272	316	360	403	—	—	—
Cheng Cycle CT - 140 MW	119	173	228	282	337	391	445	500	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	233	289	345	402	458	514	571	—	—	—
IGCC - 267 MW	201	234	267	299	332	365	398	431	463	—	—
IGCC - 534 MW	173	206	238	271	303	335	368	400	432	—	—
Fuel Cell - 0.2 MW	1263	1320	1378	1436	1494	1552	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	190	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	186	274	363	452	541	629	718	—	—	—
Supercritical Pulverized Coal - 500 MW	153	175	197	219	241	263	285	307	329	351	373
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	185	207	228	250	272	293	315	337	359	380
Supercritical Pulverized Coal - 750 MW	137	159	181	202	224	245	267	289	310	332	353
Subcritical Pulverized Coal - 250 MW	189	211	234	257	280	303	326	349	372	395	418
Subcritical Pulverized Coal - 500 MW	149	172	194	216	239	261	284	306	328	351	373
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	181	203	225	247	269	291	313	335	357	379
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	168	189	210	232	253	275	296	317	339	360
Circulating Fluidized Bed - 250 MW	197	220	244	267	291	314	338	361	385	408	432
Circulating Fluidized Bed - 500 MW	150	173	196	219	242	265	288	311	334	357	380
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	135	152	170	188	206	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	224	241	259	277	295

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost-Low 2004 Dollars ($/kW yr)
Heat Rate- High
Fuel Forecast- High

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
					Capacity Factors						
Pumped Hydro Energy Storage - 500 MW	176	207	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	145	258	370	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	93	149	205	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	148	227	307	386	466	545	625	704	784	863	943
Simple Cycle GE 7EA CT - 73 MW	102	200	299	397	496	594	693	791	890	988	1087
Simple Cycle GE 7FA CT - 148 MW	77	173	269	365	462	558	654	750	846	943	1039
Combined Cycle GE 7EA CT - 119 MW	136	197	259	320	382	443	505	566	628	689	751
Combined Cycle GE 7FA CT - 235 MW	108	164	220	276	332	388	444	500	556	612	668
Combined Cycle 2x1 GE 7FA CT - 484 MW	90	146	201	257	313	368	424	480	536	591	647
W 501F CC CT - 258 MW	102	160	218	276	333	391	449	507	565	623	681
Spark Ignition Engine - 5 MW	127	225	323	422	520	618	—	—	—	—	—
Compression Ignition Engine - 10 MW	92	176	260	345	429	513	—	—	—	—	—
Wind Energy Conversion - 50 MW	160	160	160	160	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	395	424	454	483	513	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	307	323	339	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Thermal, Solar Chimney - 200 MW	351	367	383	399	416	432	448	464	—	—	—
Solar Photovoltaic - 50 kW	771	795	820	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	272	280	289	297	306	315	323	332	341	—	—
Geothermal - 30 MW	592	592	592	592	592	592	592	592	592	—	—
Hydroelectric - New - 30 MW	364	369	374	378	383	387	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	895	975	1056	1137	1217	1298	1378	1459	—	—	—
RDF Stoker-Fired - 7 MW	1315	1401	1487	1573	1659	1745	1831	1917	—	—	—
Landfill Gas IC Engine - 5 MW	176	228	280	331	383	435	487	538	590	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	290	295	300	305	310	315	320	325	330	335	341
Sewage Sludge & Anaerobic Digestion - .085 MW	268	284	300	316	333	349	365	381	397	—	—
Humid Air Turbine Cycle CT - 450 MW	80	131	182	233	284	335	386	437	—	—	—
Kalina Cycle CC CT - 275 MW	98	151	203	255	308	360	413	465	—	—	—
Cheng Cycle CT - 140 MW	119	184	250	316	381	447	512	578	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	177	244	311	379	446	514	581	649	—	—	—
IGCC - 267 MW	201	239	277	316	354	392	430	469	507	—	—
IGCC - 534 MW	173	211	249	287	325	362	400	438	476	—	—
Fuel Cell - 0.2 MW	1263	1331	1400	1468	1537	1606	—	—	—	—	—
Peaking Microturbine - 0.03 MW	97	206	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	97	201	306	410	515	619	724	828	—	—	—
Supercritical Pulverized Coal - 500 MW	153	181	209	236	264	291	319	347	374	402	429
Supercritical Pulverized Coal, High Sulfur - 500 MW	163	189	214	240	266	291	317	342	368	394	419
Supercritical Pulverized Coal - 750 MW	137	164	191	218	245	272	299	326	353	380	407
Subcritical Pulverized Coal - 250 MW	189	217	246	275	303	332	361	389	418	447	476
Subcritical Pulverized Coal - 500 MW	149	177	205	233	261	289	317	345	373	401	429
Subcritical Pulverized Coal, High Sulfur - 500 MW	159	185	211	237	263	289	315	341	367	393	419
Supercritical Pulverized Coal, High Sulfur - 750 MW	146	171	197	222	247	272	297	323	348	373	398
Circulating Fluidized Bed - 250 MW	197	226	256	285	314	343	373	402	431	461	490
Circulating Fluidized Bed - 500 MW	150	178	207	235	264	293	321	350	378	407	436
Ohio Falls 9 and 10	130	130	130	130	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	117	138	160	181	203	224	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	246	267	289	310	332

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast- Base

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	151	201	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	223	289	355	422	488	554	620	686	753	819
Simple Cycle GE 7EA CT - 73 MW	108	190	273	355	438	520	603	685	768	850	933
Simple Cycle GE 7FA CT - 148 MW	81	163	245	327	408	490	572	654	736	818	900
Combined Cycle GE 7EA CT - 119 MW	145	196	248	299	351	402	454	505	557	608	660
Combined Cycle GE 7FA CT - 235 MW	116	163	210	257	304	351	397	444	491	538	585
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	143	189	236	283	329	376	423	470	516	563
W 501F CC CT - 258 MW	109	157	206	254	303	351	400	448	497	545	594
Spark Ignition Engine - 5 MW	141	227	312	398	483	569	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	177	251	325	399	473	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	265	310	356	402	447	493	538	584	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	133	176	219	261	304	346	389	—	—	—
Kalina Cycle CC CT - 275 MW	114	158	202	245	289	333	376	420	—	—	—
Cheng Cycle CT - 140 MW	140	195	249	304	359	413	468	523	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	269	326	382	439	495	552	609	—	—	—
IGCC - 267 MW	237	270	302	335	368	400	433	466	499	—	—
IGCC - 534 MW	207	240	272	304	336	369	401	433	465	—	—
Fuel Cell - 0.2 MW	1394	1452	1510	1568	1626	1684	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	215	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	211	300	389	477	566	655	744	—	—	—
Supercritical Pulverized Coal - 500 MW	167	191	214	237	261	284	307	330	354	377	400
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	198	218	239	260	280	301	321	342	363	383
Supercritical Pulverized Coal - 750 MW	150	173	196	219	242	265	288	311	334	357	379
Subcritical Pulverized Coal - 250 MW	206	230	254	279	303	328	352	376	401	425	450
Subcritical Pulverized Coal - 500 MW	163	187	211	234	258	282	305	329	353	376	400
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	194	214	235	256	277	298	318	339	360	381
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	180	200	220	240	261	281	301	322	342	362
Circulating Fluidized Bed - 250 MW	215	240	265	290	315	339	364	389	414	439	464
Circulating Fluidized Bed - 500 MW	164	188	212	236	261	285	309	334	358	382	407
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	146	162	179	196	213	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	230	246	263	280	297

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- Base — **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	150	199	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	220	283	346	409	472	535	598	661	724	787
Simple Cycle GE 7EA CT - 73 MW	108	186	265	344	423	501	580	659	737	816	895
Simple Cycle GE 7FA CT - 148 MW	81	159	238	316	395	473	552	630	709	787	866
Combined Cycle GE 7EA CT - 119 MW	145	194	243	292	341	390	440	489	538	587	636
Combined Cycle GE 7FA CT - 235 MW	116	161	206	250	295	340	385	430	474	519	564
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	140	185	229	274	318	363	407	452	496	541
W 501F CC CT - 258 MW	109	155	201	247	294	340	386	432	478	525	571
Spark Ignition Engine - 5 MW	141	224	306	389	471	554	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	175	246	318	389	461	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	263	308	352	397	441	485	530	574	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	131	172	213	253	294	334	375	—	—	—
Kalina Cycle CC CT - 275 MW	114	156	198	239	281	323	364	406	—	—	—
Cheng Cycle CT - 140 MW	140	192	244	296	348	400	452	504	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	266	320	374	428	482	536	590	—	—	—
IGCC - 267 MW	237	268	300	331	363	395	426	458	489	—	—
IGCC - 534 MW	207	239	270	301	332	363	394	425	456	—	—
Fuel Cell - 0.2 MW	1394	1449	1504	1560	1615	1671	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	211	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	207	292	377	463	548	633	718	—	—	—
Supercritical Pulverized Coal - 500 MW	167	188	210	231	252	273	294	315	336	357	378
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	198	219	240	261	282	303	324	344	365	386
Supercritical Pulverized Coal - 750 MW	150	171	192	213	233	254	275	295	316	337	357
Subcritical Pulverized Coal - 250 MW	206	228	250	272	294	316	338	360	382	404	426
Subcritical Pulverized Coal - 500 MW	163	184	206	227	248	270	291	312	334	355	376
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	194	215	236	258	279	300	321	342	364	385
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	180	200	221	242	262	283	303	324	345	365
Circulating Fluidized Bed - 250 MW	215	237	260	282	305	327	350	372	395	417	440
Circulating Fluidized Bed - 500 MW	164	186	208	230	252	274	296	318	340	362	384
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	146	163	180	197	214	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	231	248	265	282	299

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- Base — **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast-Low

Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
					Capacity Factors						
Pumped Hydro Energy Storage - 500 MW	195	228	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	151	201	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	223	289	355	421	487	553	619	685	751	817
Simple Cycle GE 7EA CT - 73 MW	108	190	272	354	437	519	601	683	765	848	930
Simple Cycle GE 7FA CT - 148 MW	81	163	244	326	408	489	571	653	734	816	898
Combined Cycle GE 7EA CT - 119 MW	145	196	248	299	351	402	453	505	556	608	659
Combined Cycle GE 7FA CT - 235 MW	116	163	210	256	303	350	397	444	490	537	584
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	142	189	235	282	328	375	421	468	514	561
W 501F CC CT - 258 MW	109	157	205	254	302	350	399	447	495	544	592
Spark Ignition Engine - 5 MW	141	226	312	397	483	568	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	177	251	325	399	473	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	265	311	356	402	448	494	539	585	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	133	176	218	261	303	345	388	—	—	—
Kalina Cycle CC CT - 275 MW	114	158	201	245	288	332	376	419	—	—	—
Cheng Cycle CT - 140 MW	140	194	249	303	358	412	466	521	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	269	325	381	438	494	550	607	—	—	—
IGCC - 267 MW	237	270	303	335	368	401	434	467	499	—	—
IGCC - 534 MW	207	240	272	305	337	369	402	434	466	—	—
Fuel Cell - 0.2 MW	1394	1451	1509	1567	1625	1683	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	215	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	211	299	388	477	566	654	743	—	—	—
Supercritical Pulverized Coal - 500 MW	167	189	211	233	255	277	299	321	343	365	387
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	199	221	242	264	286	307	329	351	373	394
Supercritical Pulverized Coal - 750 MW	150	172	194	215	237	258	280	302	323	345	366
Subcritical Pulverized Coal - 250 MW	206	228	251	274	297	320	343	366	389	412	435
Subcritical Pulverized Coal - 500 MW	163	186	208	230	253	275	298	320	342	365	387
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	195	217	239	261	283	305	327	349	371	393
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	181	202	223	245	266	288	309	330	352	373
Circulating Fluidized Bed - 250 MW	215	238	262	285	309	332	356	379	403	426	450
Circulating Fluidized Bed - 500 MW	164	187	210	233	256	279	302	325	348	371	394
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	147	164	182	200	218	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	236	253	271	289	307

Exhibit 8

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- Base **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	195	226	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	101	157	213	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	157	236	316	395	475	554	634	713	793	872	952
Simple Cycle GE 7EA CT - 73 MW	108	206	305	403	502	600	699	797	896	994	1093
Simple Cycle GE 7FA CT - 148 MW	81	177	273	369	466	562	658	754	850	947	1043
Combined Cycle GE 7EA CT - 119 MW	145	206	268	329	391	452	514	575	637	698	760
Combined Cycle GE 7FA CT - 235 MW	116	172	228	284	340	396	452	508	564	620	676
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	152	207	263	319	374	430	486	542	597	653
W 501F CC CT - 258 MW	109	167	225	283	340	398	456	514	572	630	688
Spark Ignition Engine - 5 MW	141	239	337	436	534	632	—	—	—	—	—
Compression Ignition Engine - 10 MW	103	187	271	356	440	524	—	—	—	—	—
Wind Energy Conversion - 50 MW	191	191	191	191	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	—	—	—
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	—	—	—
Solar Photovoltaic - 50 kW	958	982	1007	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	—	—
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	—	—
Hydroelectric - New - 30 MW	402	407	412	416	421	425	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	—	—	—
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	—	—	—
Landfill Gas IC Engine - 5 MW	219	271	323	374	426	478	530	581	633	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	—	—
Humid Air Turbine Cycle CT - 450 MW	91	142	193	244	295	346	397	448	—	—	—
Kalina Cycle CC CT - 275 MW	114	167	219	271	324	376	429	481	—	—	—
Cheng Cycle CT - 140 MW	140	205	271	337	402	468	533	599	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	213	280	347	415	482	550	617	685	—	—	—
IGCC - 267 MW	237	275	313	352	390	428	466	505	543	—	—
IGCC - 534 MW	207	245	283	321	359	396	434	472	510	—	—
Fuel Cell - 0.2 MW	1394	1462	1531	1599	1668	1737	—	—	—	—	—
Peaking Microturbine - 0.03 MW	122	231	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	122	226	331	435	540	644	749	853	—	—	—
Supercritical Pulverized Coal - 500 MW	167	195	223	250	278	305	333	361	388	416	443
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	203	228	254	280	305	331	356	382	408	433
Supercritical Pulverized Coal - 750 MW	150	177	204	231	258	285	312	339	366	393	420
Subcritical Pulverized Coal - 250 MW	206	234	263	292	320	349	378	406	435	464	493
Subcritical Pulverized Coal - 500 MW	163	191	219	247	275	303	331	359	387	415	443
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	199	225	251	277	303	329	355	381	407	433
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	184	210	235	260	285	310	336	361	386	411
Circulating Fluidized Bed - 250 MW	215	244	274	303	332	361	391	420	449	479	508
Circulating Fluidized Bed - 500 MW	164	192	221	249	278	307	335	364	392	421	450
Ohio Falls 9 and 10	144	144	144	144	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	129	150	172	193	215	236	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	258	279	301	322	344

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- High **2004 Dollars ($/kW yr)**
Heat Rate-Low
Fuel Forecast- Base

	Capacity Factors										
Technology	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	167	217	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	166	232	298	364	431	497	563	629	695	762	828
Simple Cycle GE 7EA CT - 73 MW	114	196	279	361	444	526	609	691	774	856	939
Simple Cycle GE 7FA CT - 148 MW	86	168	250	332	413	495	577	659	741	823	905
Combined Cycle GE 7EA CT - 119 MW	155	206	258	309	361	412	464	515	567	618	670
Combined Cycle GE 7FA CT - 235 MW	123	170	217	264	311	358	404	451	498	545	592
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	148	194	241	288	334	381	428	475	521	568
W 501F CC CT - 258 MW	116	164	213	261	310	358	407	455	504	552	601
Spark Ignition Engine - 5 MW	155	241	326	412	497	583	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	187	261	335	409	483	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	309	354	400	446	491	537	582	628	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	144	187	230	272	315	357	400	—	—	—
Kalina Cycle CC CT - 275 MW	131	175	219	262	306	350	393	437	—	—	—
Cheng Cycle CT - 140 MW	160	215	269	324	379	433	488	543	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	304	361	417	474	530	587	644	—	—	—
IGCC - 267 MW	273	306	338	371	404	436	469	502	535	—	—
IGCC - 534 MW	240	273	305	337	369	402	434	466	498	—	—
Fuel Cell - 0.2 MW	1526	1584	1642	1700	1758	1816	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	239	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	235	324	413	501	590	679	768	—	—	—
Supercritical Pulverized Coal - 500 MW	181	205	228	251	275	298	321	344	368	391	414
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	213	233	254	275	295	316	336	357	378	398
Supercritical Pulverized Coal - 750 MW	162	185	208	231	254	277	300	323	346	369	391
Subcritical Pulverized Coal - 250 MW	223	247	271	296	320	345	369	393	418	442	467
Subcritical Pulverized Coal - 500 MW	176	200	224	247	271	295	318	342	366	389	413
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	208	228	249	270	291	312	332	353	374	395
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	194	214	234	254	275	295	315	336	356	376
Circulating Fluidized Bed - 250 MW	232	257	282	307	332	356	381	406	431	456	481
Circulating Fluidized Bed - 500 MW	178	202	226	250	275	299	323	348	372	396	421
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	157	173	190	207	224	[redacted]				
Minimum Levelized $/kW	0	37	73	110	148	183	241	257	274	291	308

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- High — **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast-Low

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	166	215	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	166	229	292	355	418	481	544	607	670	733	796
Simple Cycle GE 7EA CT - 73 MW	114	192	271	350	429	507	586	665	743	822	901
Simple Cycle GE 7FA CT - 148 MW	86	164	243	321	400	478	557	635	714	792	871
Combined Cycle GE 7EA CT - 119 MW	155	204	253	302	351	400	450	499	548	597	646
Combined Cycle GE 7FA CT - 235 MW	123	168	213	257	302	347	392	437	481	526	571
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	145	190	234	279	323	368	412	457	501	546
W 501F CC CT - 258 MW	116	162	208	254	301	347	393	439	485	532	578
Spark Ignition Engine - 5 MW	155	238	320	403	485	568	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	185	256	328	399	471	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	307	352	396	441	485	529	574	618	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	142	183	224	264	305	345	386	—	—	—
Kalina Cycle CC CT - 275 MW	131	173	215	256	298	340	381	423	—	—	—
Cheng Cycle CT - 140 MW	160	212	264	316	368	420	472	524	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	301	355	409	463	517	571	625	—	—	—
IGCC - 267 MW	273	304	336	367	399	431	462	494	525	—	—
IGCC - 534 MW	240	272	303	334	365	396	427	458	489	—	—
Fuel Cell - 0.2 MW	1526	1581	1636	1692	1747	1803	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	235	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	231	316	401	487	572	657	742	—	—	—
Supercritical Pulverized Coal - 500 MW	181	202	224	245	266	287	308	329	350	371	392
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	213	234	255	276	297	318	339	359	380	401
Supercritical Pulverized Coal - 750 MW	162	183	204	225	245	266	287	307	328	349	369
Subcritical Pulverized Coal - 250 MW	223	245	267	289	311	333	355	377	399	421	443
Subcritical Pulverized Coal - 500 MW	176	197	219	240	261	283	304	325	347	368	389
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	208	229	250	272	293	314	335	356	378	399
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	194	214	235	256	276	297	317	338	359	379
Circulating Fluidized Bed - 250 MW	232	254	277	299	322	344	367	389	412	434	457
Circulating Fluidized Bed - 500 MW	178	200	222	244	266	288	310	332	354	376	398
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	157	174	191	208	225	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	242	259	276	293	310

Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- High **2004 Dollars ($/kW yr)**
Heat Rate- Base
Fuel Forecast- High

Technology	Capacity Factors 0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	171	225	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	166	242	318	393	469	545	621	697	773	849	925
Simple Cycle GE 7EA CT - 73 MW	114	208	302	396	491	585	679	773	867	962	1056
Simple Cycle GE 7FA CT - 148 MW	86	178	270	363	455	547	640	732	824	917	1009
Combined Cycle GE 7EA CT - 119 MW	155	214	273	331	390	449	508	567	625	684	743
Combined Cycle GE 7FA CT - 235 MW	123	177	230	284	337	391	444	498	551	605	658
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	154	207	261	314	367	420	473	527	580	633
W 501F CC CT - 258 MW	116	171	227	282	337	393	448	504	559	614	670
Spark Ignition Engine - 5 MW	155	250	345	439	534	629	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	194	276	357	439	520	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	313	363	413	463	513	563	613	663	—	—
TDF Multi-Fuel CFB (10% *Co-fire*) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	151	199	248	297	345	394	443	—	—	—
Kalina Cycle CC CT - 275 MW	131	181	231	281	331	381	431	481	—	—	—
Cheng Cycle CT - 140 MW	160	223	285	348	411	473	536	599	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	312	377	441	506	570	635	700	—	—	—
IGCC - 267 MW	273	310	346	383	420	456	493	530	567	—	—
IGCC - 534 MW	240	277	313	349	385	422	458	494	530	—	—
Fuel Cell - 0.2 MW	1526	1591	1657	1723	1789	1855	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	251	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	246	346	446	547	647	747	847	—	—	—
Supercritical Pulverized Coal - 500 MW	181	208	234	261	287	313	340	366	393	419	445
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	217	241	266	291	315	340	364	389	414	438
Supercritical Pulverized Coal - 750 MW	162	188	214	240	266	292	318	344	370	396	421
Subcritical Pulverized Coal - 250 MW	223	250	277	305	332	360	387	414	442	469	497
Subcritical Pulverized Coal - 500 MW	176	203	230	256	283	310	336	363	390	416	443
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	212	237	262	287	312	337	362	387	412	437
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	197	222	246	270	294	318	343	367	391	415
Circulating Fluidized Bed - 250 MW	232	260	288	316	344	372	400	428	456	484	512
Circulating Fluidized Bed - 500 MW	178	205	232	260	287	315	342	369	397	424	452
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	160	181	201	222	242	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	263	283	304	324	345

Exhibit 8

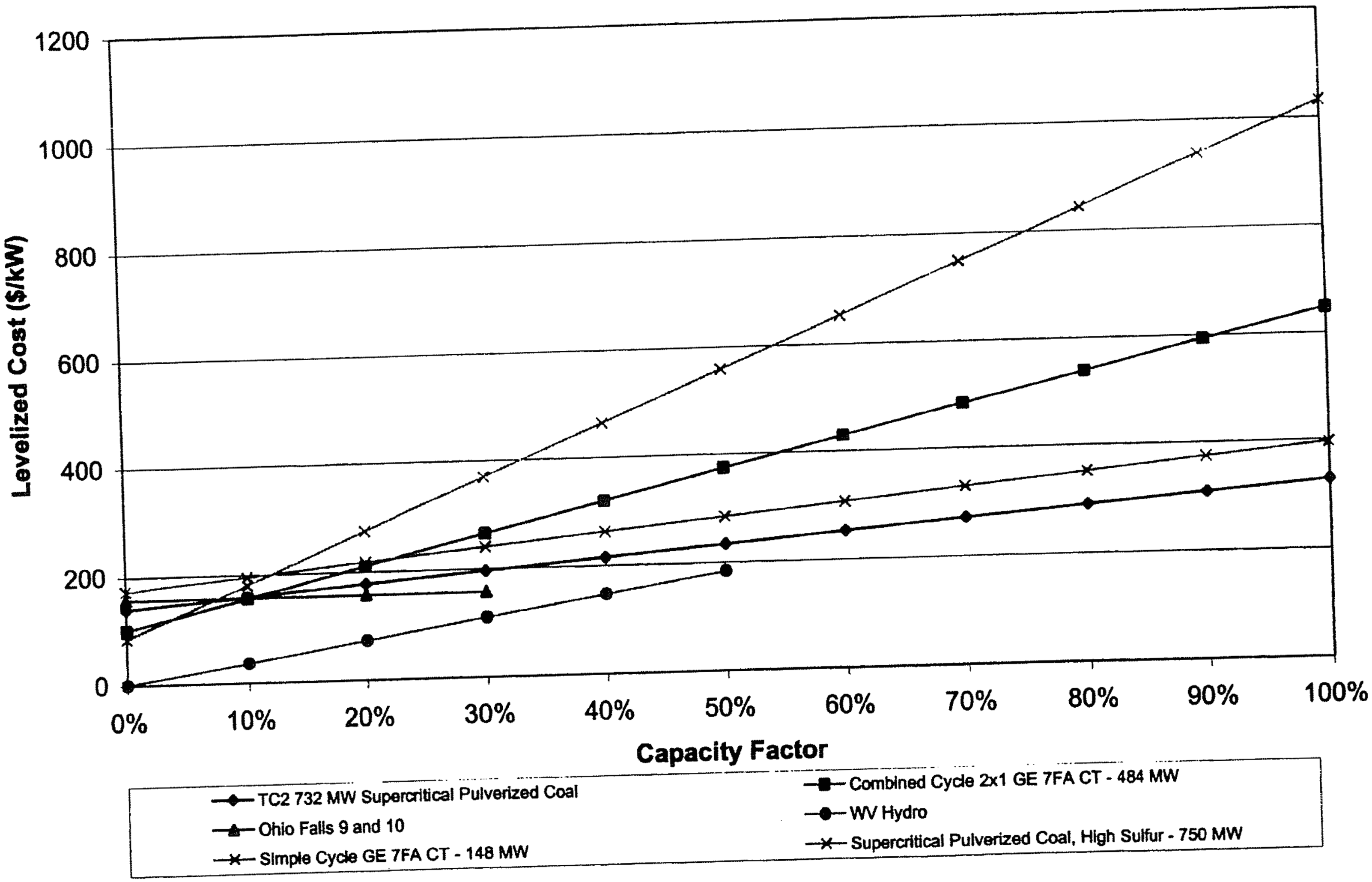
Levelized Dollars at Various Capacity Factors With SO2 Adders, with CO2 Adders, and with NOx Adders

Capital Cost- High **2004 Dollars ($/kW yr)**
Heat Rate- High
Fuel Forecast- Base

	Capacity Factors										
Technology	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	232	263	—	—	—	—	—	—	—	—	—
Lead-Acid Battery Energy Storage - 5 MW	187	300	412	—	—	—	—	—	—	—	—
Compressed Air Energy Storage - 500 MW	117	170	223	—	—	—	—	—	—	—	—
Simple Cycle GE LM6000 CT - 31 MW	168	239	311	384	457	530	603	675	748	821	894
Simple Cycle GE 7EA CT - 73 MW	114	204	295	385	475	566	656	747	837	927	1018
Simple Cycle GE 7FA CT - 148 MW	86	175	264	353	442	531	620	709	798	887	976
Combined Cycle GE 7EA CT - 119 MW	155	211	268	324	381	437	493	550	606	663	719
Combined Cycle GE 7FA CT - 235 MW	123	174	226	277	329	380	431	483	534	586	637
Combined Cycle 2x1 GE 7FA CT - 484 MW	101	152	203	254	305	356	408	459	510	561	612
W 501F CC CT - 258 MW	116	169	222	275	328	381	434	488	541	594	647
Spark Ignition Engine - 5 MW	155	247	339	430	522	614	—	—	—	—	—
Compression Ignition Engine - 10 MW	113	192	271	350	429	508	—	—	—	—	—
Wind Energy Conversion - 50 MW	221	221	221	221	—	—	—	—	—	—	—
Solar Thermal, Parabolic Trough - 100 MW	593	622	652	681	711	—	—	—	—	—	—
Solar Thermal, Parabolic Dish - 1.2 MW	461	477	493	—	—	—	—	—	—	—	—
Solar Thermal, Central Receiver - 50 MW	790	806	822	838	855	871	887	903	—	—	—
Solar Thermal, Solar Chimney - 200 MW	527	543	559	575	592	608	624	640	—	—	—
Solar Photovoltaic - 50 kW	1144	1168	1193	—	—	—	—	—	—	—	—
Biomass (Co-Fire) - 27.5MW	370	378	387	395	404	413	421	430	439	—	—
Geothermal - 30 MW	735	735	735	735	735	735	735	735	735	—	—
Hydroelectric - New - 30 MW	440	445	450	454	459	463	—	—	—	—	—
WV Hydro	[redacted]						—	—	—	—	—
MSW Mass Burn - 7 MW	1158	1238	1319	1400	1480	1561	1641	1722	—	—	—
RDF Stoker-Fired - 7 MW	1666	1752	1838	1924	2010	2096	2182	2268	—	—	—
Landfill Gas IC Engine - 5 MW	263	312	361	409	458	507	556	604	653	—	—
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	400	405	410	415	420	425	430	435	440	445	451
Sewage Sludge & Anaerobic Digestion - .085 MW	402	418	434	450	467	483	499	515	531	—	—
Humid Air Turbine Cycle CT - 450 MW	102	149	195	242	289	335	382	429	—	—	—
Kalina Cycle CC CT - 275 MW	131	179	227	275	323	371	419	467	—	—	—
Cheng Cycle CT - 140 MW	160	220	280	340	400	460	520	580	—	—	—
Pressurized Fluidized Bed Combustion - 250 MW	248	309	371	433	495	557	619	681	—	—	—
IGCC - 267 MW	273	308	344	379	415	451	486	522	557	—	—
IGCC - 534 MW	240	276	311	346	381	416	451	486	521	—	—
Fuel Cell - 0.2 MW	1526	1589	1652	1715	1778	1842	—	—	—	—	—
Peaking Microturbine - 0.03 MW	146	247	—	—	—	—	—	—	—	—	—
Baseload Microturbine - 0.03 MW	146	243	339	436	532	629	725	822	—	—	—
Supercritical Pulverized Coal - 500 MW	181	207	233	258	284	309	335	361	386	412	437
Supercritical Pulverized Coal, High Sulfur - 500 MW	192	215	237	259	282	304	327	349	371	394	416
Supercritical Pulverized Coal - 750 MW	162	188	213	238	263	288	313	338	363	388	413
Subcritical Pulverized Coal - 250 MW	223	249	276	302	329	356	382	409	435	462	489
Subcritical Pulverized Coal - 500 MW	176	202	228	254	280	306	332	358	384	410	436
Subcritical Pulverized Coal, High Sulfur - 500 MW	187	210	232	255	278	300	323	346	368	391	414
Supercritical Pulverized Coal, High Sulfur - 750 MW	173	195	217	239	261	283	305	327	349	371	393
Circulating Fluidized Bed - 250 MW	232	259	287	314	341	368	396	423	450	478	505
Circulating Fluidized Bed - 500 MW	178	204	231	258	284	311	338	364	391	418	445
Ohio Falls 9 and 10	157	157	157	157	—	—	—	—	—	—	—
TC2 732 MW Supercritical Pulverized Coal	140	158	177	195	213	232	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	250	269	287	305	324

Least Cost Technologies Considered For Further Analysis

Base Capital, Base Heatrate, Base Fuel

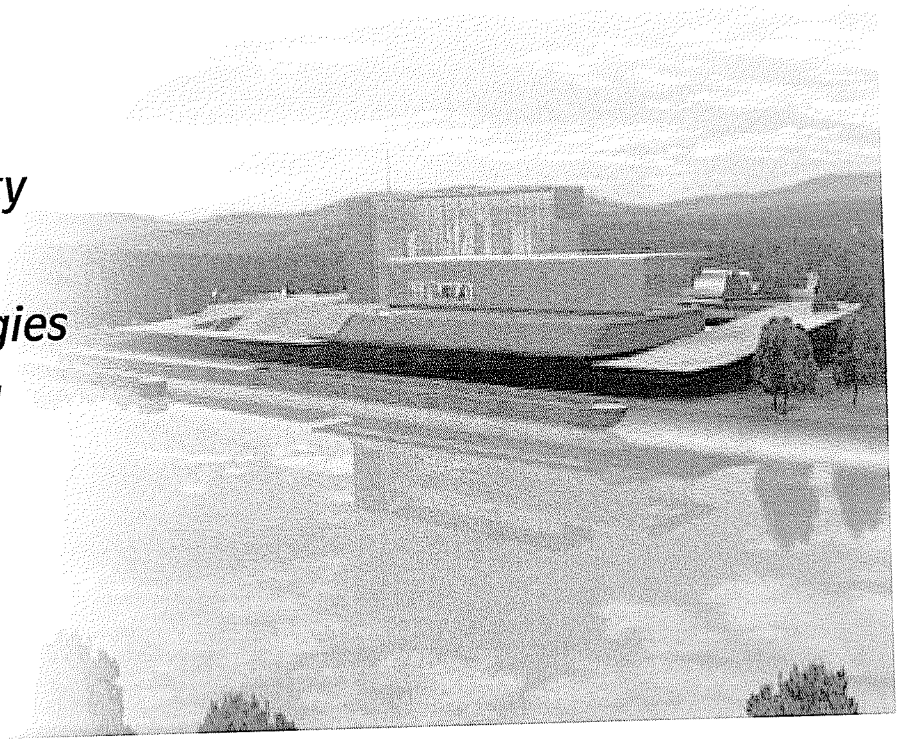


e·on | U.S.

FutureGen
Update for the Kentucky Public Service Commission
August 2007

What is FutureGen?

- Commercial-scale 275-MW Plant
- 1 million tons/year CO_2 captured and sequestered (No other power generation project doing this)
- Co-production of Hydrogen and electricity
- "Living laboratory" to test and validate cutting-edge technologies
- Public-private partnership (Cost Sharing 74/26)
- Stakeholder involvement
- International participation
- On-line end of 2012



Our purpose today: Provide KYPSC an overview of FutureGen and answer questions

FutureGen – the Right Partners

Industry
- Twelve leading companies with operations on six continents
- Investing $250M* in project with no expectation of financial return

Governments
- United States, China, India, South Korea, and Japan

Uniquely positioned to build global acceptance of near-zero emission coal technology

ANGLO AMERICAN
AEP
RIO TINTO ENERGY AMERICA
中国华能集团公司 CHINA HUANENG GROUP
CONSOL ENERGY
xstrata
FOUNDATION COAL CORPORATION
bhpbilliton
e·on | U.S.
ppl
SOUTHERN COMPANY Energy to Serve Your World®
Peabody

FutureGen Current Status

- DOE working through the NEPA process to provide the site Record of Decision to the Alliance
- Final Site Selection scheduled for late 2007
- Begin Facility Permitting

- Facility Design Work
  - RFI's released for Gasifier, Turbine, Shift Catalyst and AGRU
  - Developing RFP's for key equipment
  - Plans to procure key equipment in the next year

- Sequestration
  - RFP's for drilling and seismic work prepared
  - Revision of cost estimate as a result of work performed

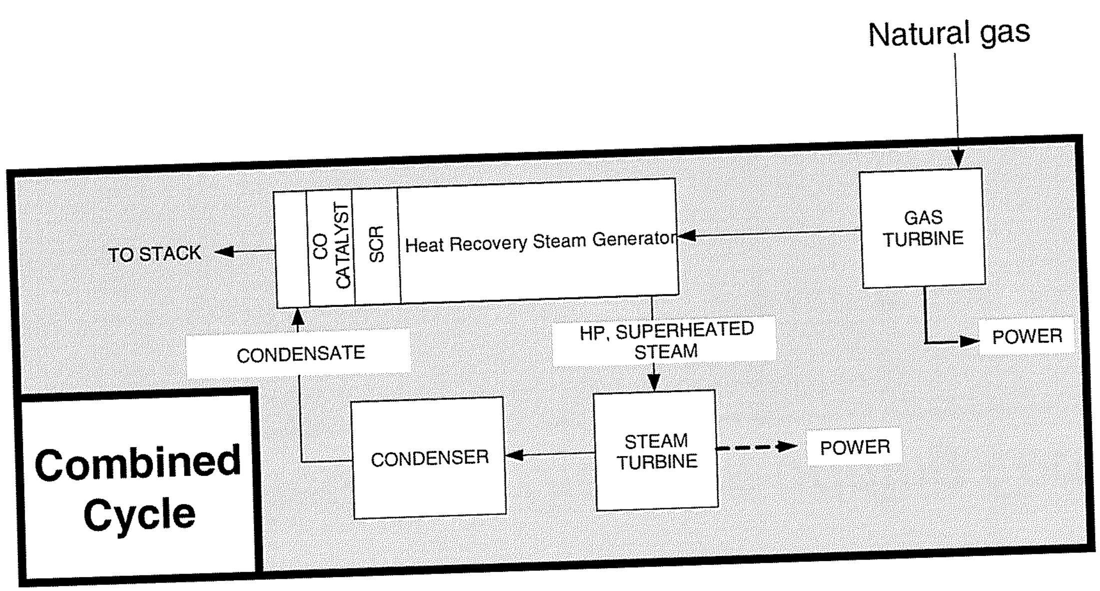
- Update Costing and Contracting Strategy

- End of this contract period with the DOE is scheduled for September 2008

FutureGen Project Cost Estimate

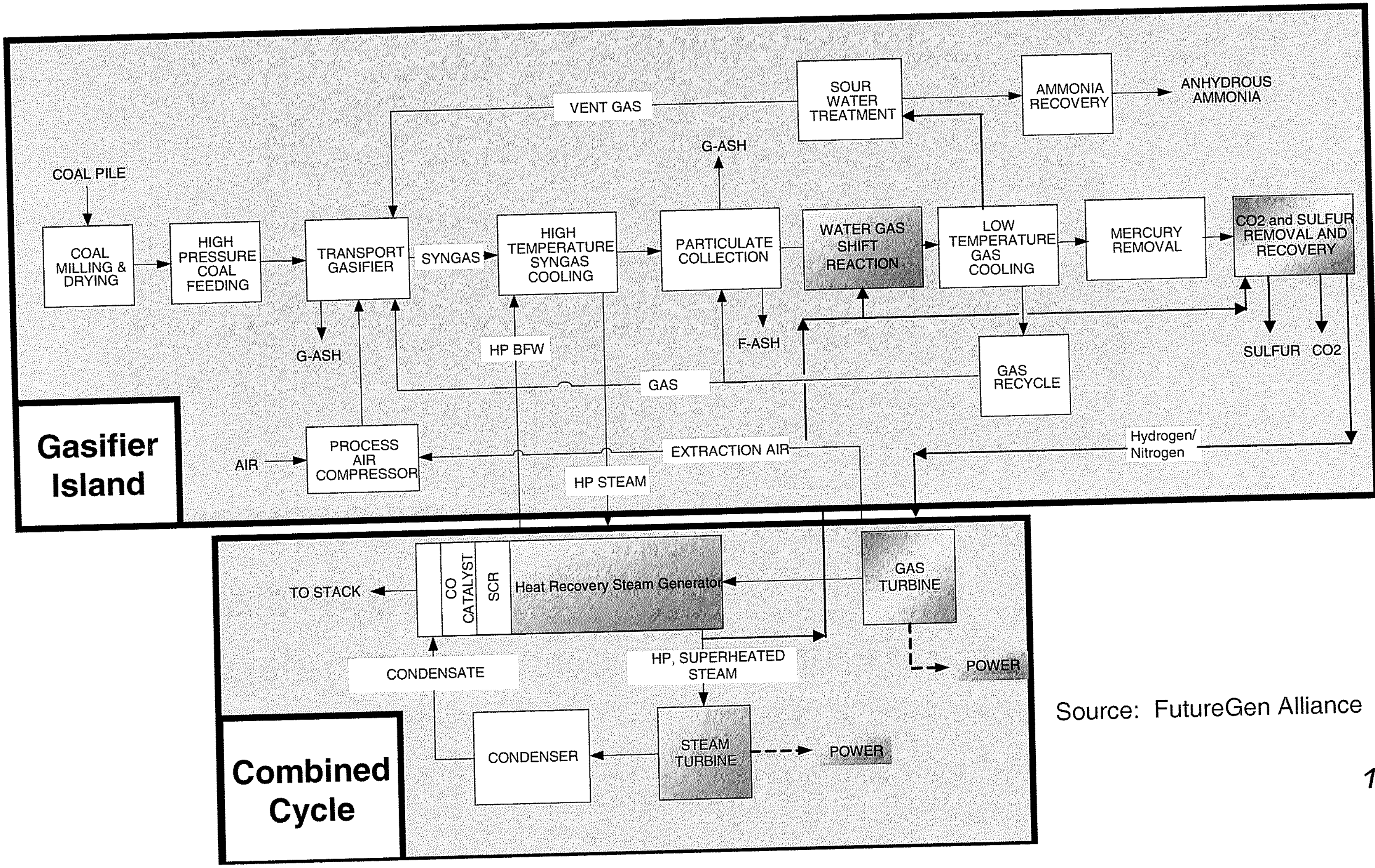
Cost Estimate	Cost	Basis
Alliance Cost Estimate	*$1,187M*	*3Q 2006 dollars*
Alliance Cost Estimate	*$1,484M*	*future as-spent dollars (5.2%/yr)*
Alliance Cost Estimate	*$954M*	*de-escalated to 1Q 2004 dollars*
DOE Report to Congress Budget	*$950M*	*1Q 2004 dollars*

Transitioning from Natural Gas Combined Cycle to Integrated Gasification Combined Cycle (IGCC) Adds Cost and Complexity



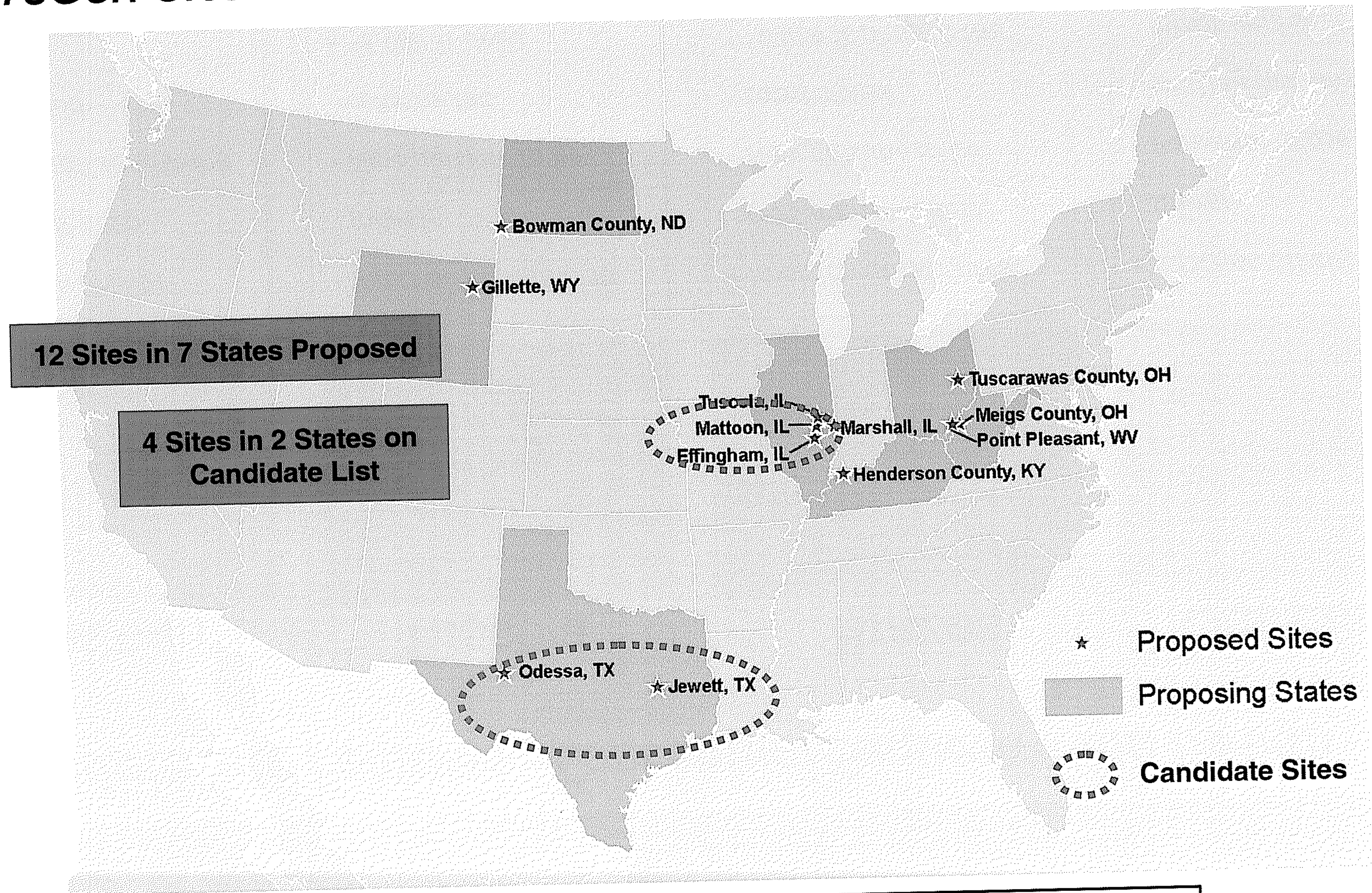
Source: FutureGen Alliance

TRIG™ with Carbon Separation Technology Integrated



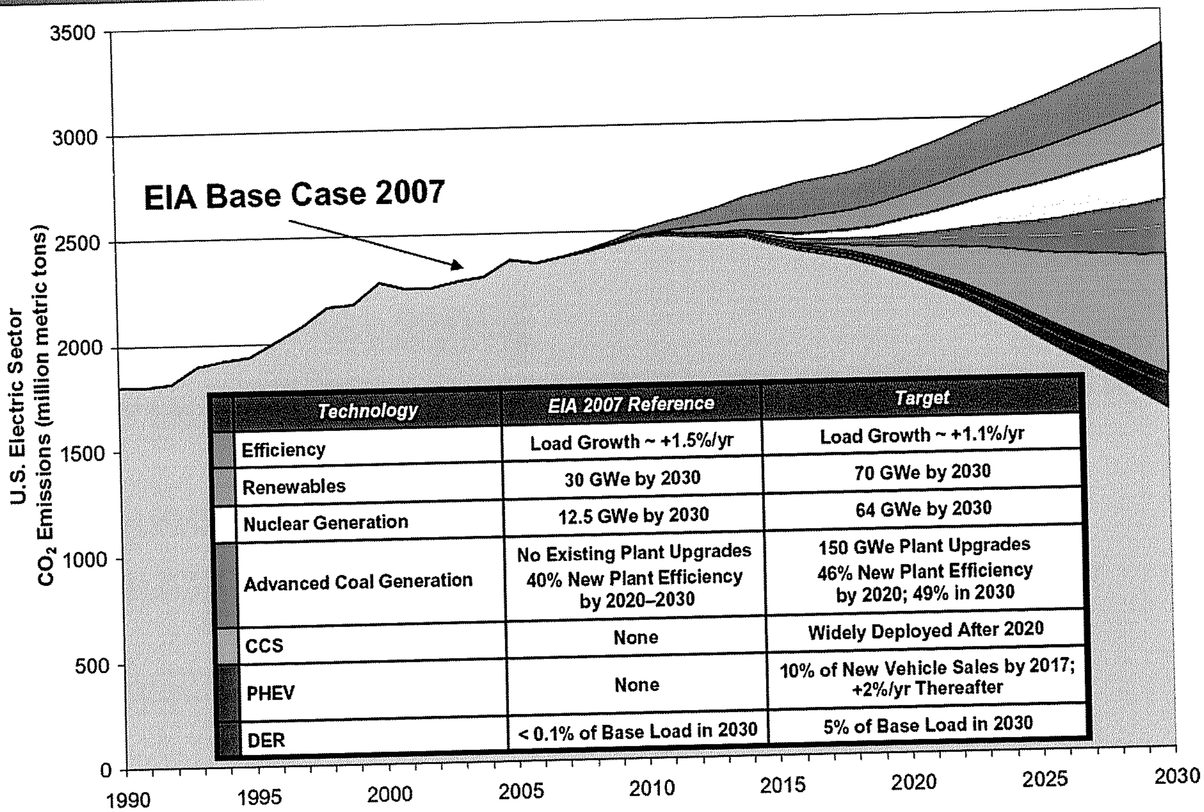
Source: FutureGen Alliance

FutureGen Site Selection



FutureGen Board to decide early November/late December

CO_2 Reductions ... Technical Potential*



Technology	EIA 2007 Reference	Target
Efficiency	Load Growth ~ +1.5%/yr	Load Growth ~ +1.1%/yr
Renewables	30 GWe by 2030	70 GWe by 2030
Nuclear Generation	12.5 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Existing Plant Upgrades 40% New Plant Efficiency by 2020–2030	150 GWe Plant Upgrades 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Vehicle Sales by 2017; +2%/yr Thereafter
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

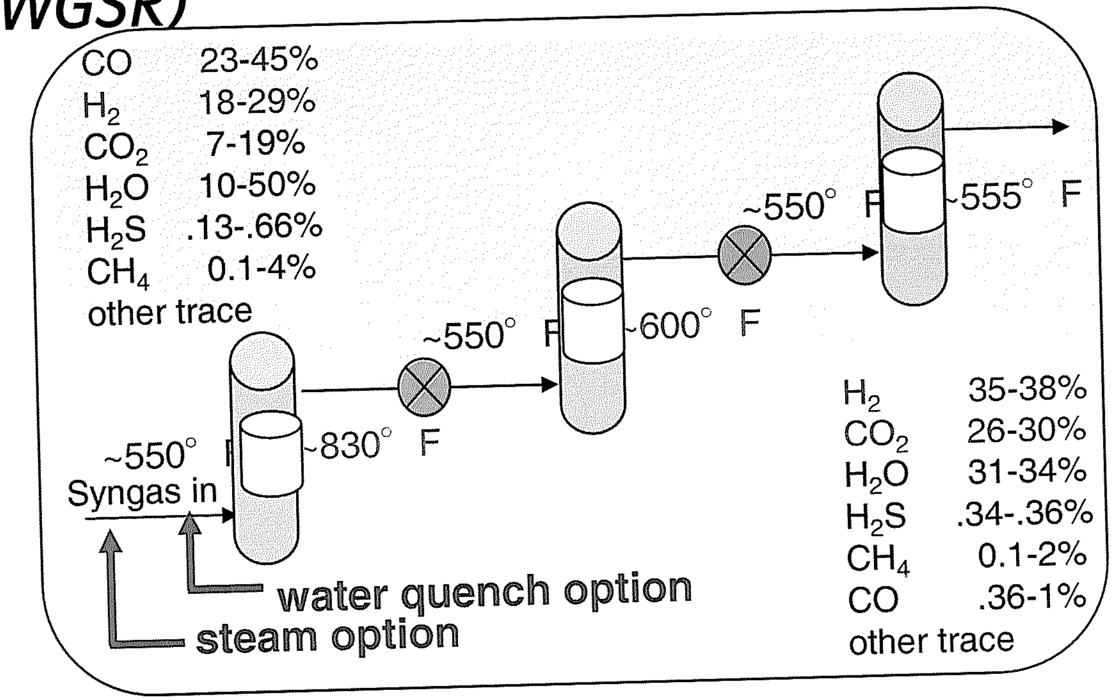
* *Achieving all targets is very aggressive, but potentially feasible.*

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Questions?

Water Gas Shift Reaction (WGSR)

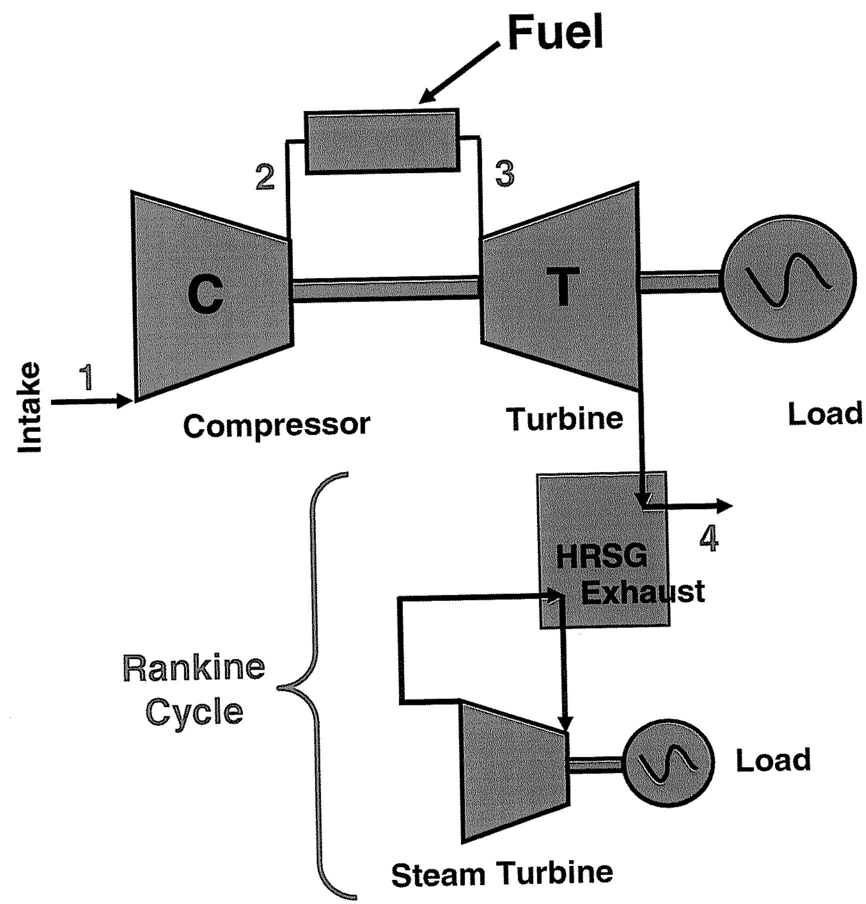
- *"Sour gas" or "raw gas" shift*
- *Place where energy content in CO*
- *"shifted" to more H_2*
- *Maximize H_2 in syngas*
- *Reaction is:*
  - **Equilibrium**
    - ♦*Multiple steps required for maximum conversion*
    - ♦*H_2O must be added*
  - **Exothermic**
    - ♦*Intermediate cooling required*
  - **Catalytic**
    - ♦*Operating temperature limit (900°F)*
    - ♦*Take steps to avoid catalyst poisoning*



$$CO + H_2O \Leftrightarrow CO_2 + H_2$$
$$COS + H_2O \Leftrightarrow CO_2 + H_2S$$
$$HCN + H_2O \Leftrightarrow CO + NH_3$$

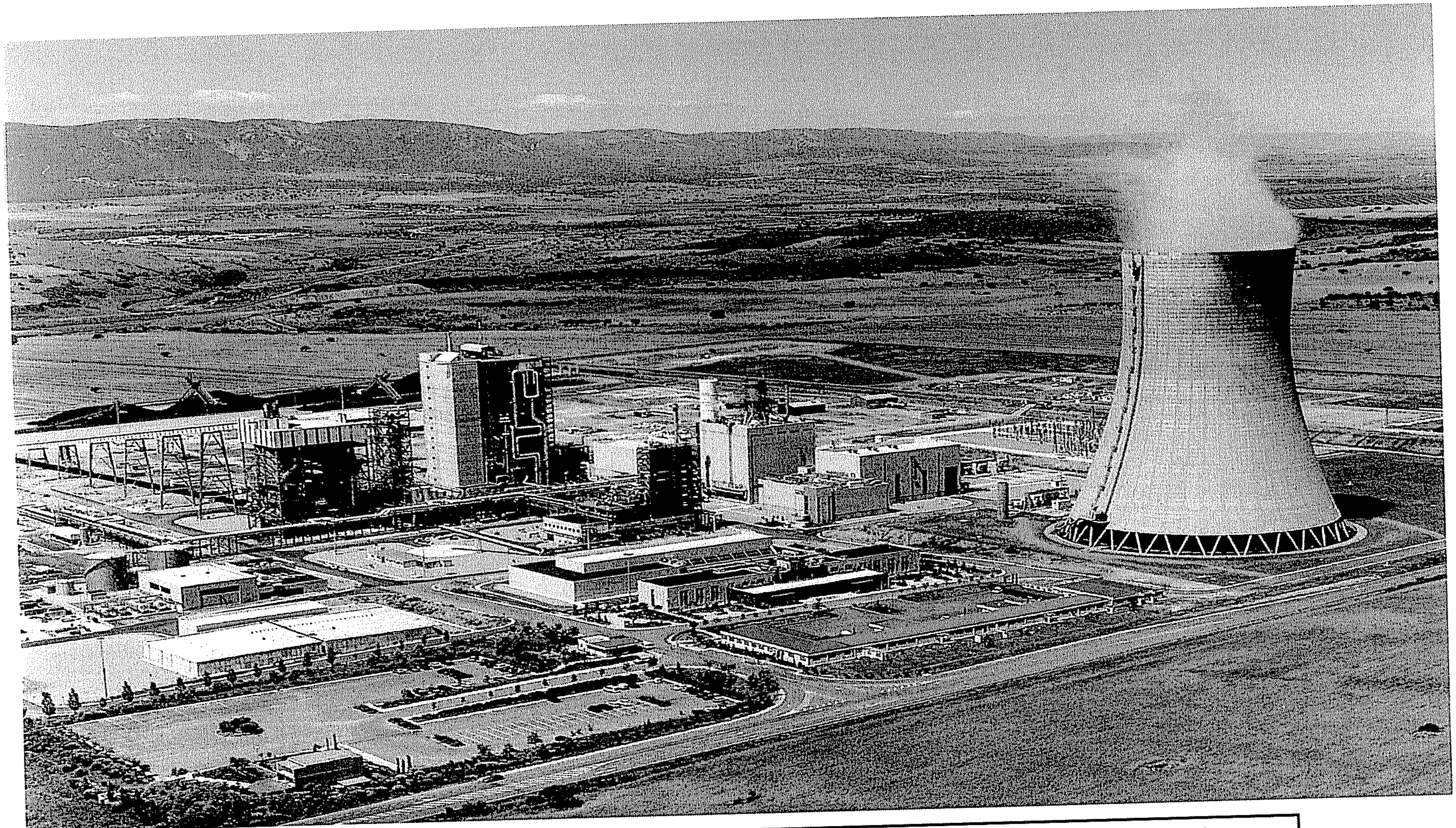
Gas Turbine (GT) Basics

- GT thermodynamics: Brayton Cycle
  - Air compression (1-2)
  - Heat addition (2-3)
  - Gas expansion (3-4)
  - Heat rejection (4-1)
- Brayton cycle alone:
  - 'Simple Cycle'
- Brayton cycle coupled with Rankine steam cycle:
  - 'Combined Cycle'



Simple Cycle Combustion Turbines – Trimble County 5 & 6

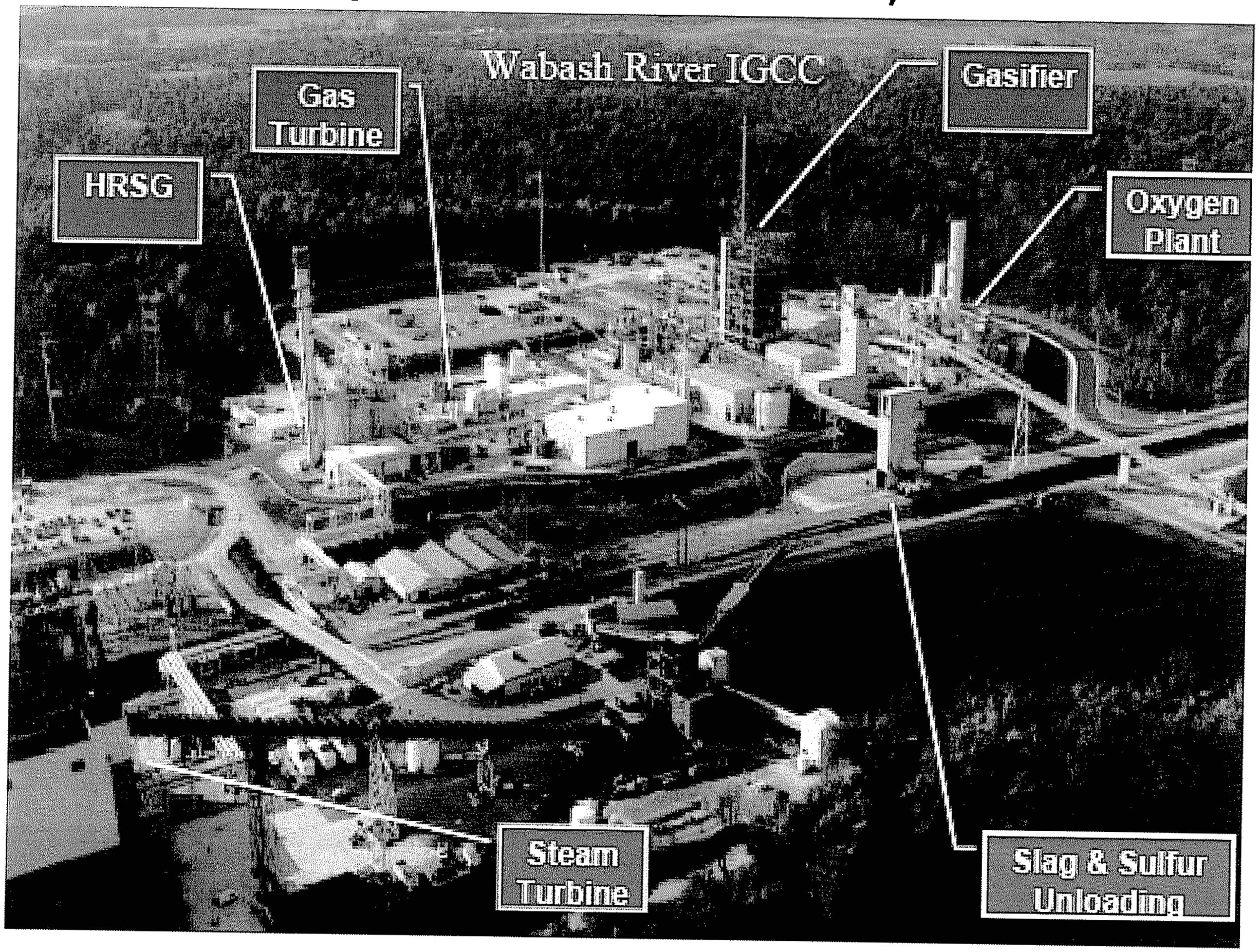
IGCC located in Puertollano, Spain



Source: FutureGen Alliance

An IGCC site is the similar size of a pulverized coal plant

Wabash River IGCC plant in Terre Haute, Indiana



Source: ConocoPhillips

One of two U.S. IGCC plants for power generation