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PUBLIC SERVICE
COMMISSION

VIA OVERNIGHT MAIL

June 7, 2005

Beth A. O'Donnell, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Administrative Case No. 2005-00090

Dear Ms. O'Donnell:

Please find enclosed the original and twelve copies of the Comments of the Kentucky Industrial Utility Customers, Inc., filed in the above-referenced matter.

By copy of this letter, all parties listed on the attached Certificate of Service been served. Please place these documents of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service
A. W. Turner, Esq.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy, by regular U.S. mail (unless otherwise noted) to all parties on the 7th day of June, 2005.

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Michael L. Kurtz, Esq.

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JUN 08 2005

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ASSESSMENT OF KENTUCKY'S ELECTRIC GENERATION, TRANSMISSION AND DISTRIBUTION NEEDS	))))	**ADMINISTRATIVE CASE NO. 2005-00090**

COMMENTS OF
THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

Governor Fletcher's February 7, 2005 Executive Order No. 2005-121 required the Kentucky Public Service Commission (Commission), the Commerce Cabinet, and the Environmental and Public Protection Cabinet to develop an electricity Strategic Blueprint. The Executive Order listed many goals. We read the Executive Order as setting forth three basic objectives.

<u>One</u>: The regulatory process in Kentucky should ensure that utilities continue to be able to make sufficient investments in electricity infrastructure (generation, transmission and distribution) to reliably serve native load.

<u>Two</u>: The regulatory process should protect Kentucky's low cost advantage and maintain affordable rates for all ratepayers.

<u>Three</u>: The regulatory process should preserve Kentucky's commitment to environmental protection.

These three objectives can be conflicting. For example, Kentucky's low cost advantage cannot be maintained if uneconomic infrastructure investments are encouraged. Nor can Kentucky's low cost advantage be maintained if unnecessary rate recovery devices are implemented which accelerate cost recovery of infrastructure investments.

Kentucky is in its enviable position today because past regulatory policies were based on sound principles. Other states experimented with mandated expensive demand side management (DSM), mandated high-priced PURPA contracts, expensive, uneconomic and sometimes exotic technologies to lower emissions, and retail deregulation. The results have been almost uniformly bad for customers. But not Kentucky. Kentucky's adherence to least cost planning and cost-of-service pricing has resulted in investment grade investor-owned utilities with ready access to capital markets and low rates. By requiring that both supply side and demand side resources meet least cost planning criteria, the Commission has ensured that ratepayers do not subsidize uneconomic projects. Least cost planning should continue for all supply side and demand side resources, including renewable energy resources and new clean coal technologies.

With this background, our Comments will focus on the three questions posed by the Commission.

1. <u>What additional information or data, if any, should the Commission consider in developing the Strategic Blueprint?</u>

Information concerning how the utilities propose to finance their new capital additions should be part of this record. Kentucky's investor-owned utilities (IOUs) are all investment grade. There should be no impediment to their ability to finance new infrastructure investments. The existing rate recovery mechanisms – base rate case, fuel adjustment clause, DSM rider, and environmental surcharge have proven to be more than adequate to finance today's solid infrastructure. There is no evidence that any new riders or surcharges are needed.

The generation and transmission cooperatives are different. East Kentucky Power Cooperative (EKPC) and Big Rivers have historically borrowed from the Rural Utilities Services (RUS) through a long and cumbersome process. Given its current financial situation, Big Rivers may no longer have ready access to RUS financing.

This record would be more informative if the utilities provided information on how they intend to finance their major new capital additions. If lower cost forms of financing are available, then the companies and consumers would both benefit.

The Commission should seek additional information on how Kenergy/Big Rivers plans on reliably meeting the 860 MW capacity needs of Alcan Primary Products and Century Aluminum, KIUC's two largest members (also the two largest power users in the state), when their current Commission approved power contracts expire in 2010/2011. This is a complex matter that involves the parties mentioned above as well as non-regulated subsidiaries of LG&E Energy. Alcan/Century have intervened separately as well as through KIUC and have filed separate comments. No Strategic Blueprint could be complete without addressing this 860 MW question.

2. <u>What are the top issues facing the electric power industry over the next 20 years?</u>

The most critical issue may be the ability of Kentucky's coal-based utilities to comply with increasing environmental requirements and still maintain low rates. One thing is clear. Without significant incentives from the federal government, integrated gasification combined cycle (IGCC) does not appear to be the answer. Attached is a March 10, 2005 report by the Electric Power Research Institute (EPRI) which concludes that IGCC is 17-19% more expensive than conventional clean coal plants. (Appendix A). IGCC is 17-19% more expensive because of higher capital costs and because the technology is less reliable. AEP has announced that it is considering building an IGCC in Kentucky for inclusion in Kentucky Power's rates. This proposition is questionable not only because IGCC is more expensive and more risky than conventional clean coal technology, but also because Kentucky Power does not need additional base load power. The attached load duration curves show that Kentucky Power can meet its native load with its existing 1450 MW of base load capacity during virtually all hours of the year. (Appendix B). Given this situation, it would not be appropriate for the Strategic Blueprint to recommend any new rate mechanism to expedite or guarantee cost recovery of an IGCC for any utility. Significant incentives for IGCC are currently proposed in both the House and Senate versions of the energy legislation pending in Congress. If such incentives pass, and if the utility needs new base load power, then IGCC may be appropriate.

Because environmental compliance is expected to be very costly for coal-based utilities, the Strategic Blueprint should include consideration of methods to reduce the financing costs of new environmental control facilities. One such method is securitization. Securitization is a widely accepted form of asset-based financing that can substantially reduce the cost of environmental compliance by allowing for 100% debt financing at the most attractive investment grade rates. In April 2005, West Virginia enacted a securitization law which allows environmental control facilities to be financed at the lowest possible cost. (Appendix C). In May 2005, an application was made by Allegheny Power to securitize the cost of a $338 million scrubber. There the utility demonstrated that securitization would save ratepayers $340 million over the life of the scrubber compared to traditional rate base financing. Wisconsin also recently enacted legislation to permit securitization financing for pollution control facilities. At least 10 other states have securitization authority as a means to reduce stranded costs.

In order to maintain Kentucky's low rate advantage while simultaneously achieving environmental compliance for coal facilities, securitization should be considered in the Strategic Blueprint. Securitization is a financing option. It does not need to be a requirement. It would be an incremental improvement to the environmental financing options currently available to Kentucky's utilities and would be a natural extension of the environmental surcharge process.

3. <u>What barriers, if any, exist to meeting future investment needs in electric power infrastructure in Kentucky?</u>

The current methods of the rate recovery (base rate case, fuel adjustment clause, DSM rider, and environmental surcharge) have allowed the IOU and cooperative utilities to operate successfully. No additional rate surcharges or other recovery devices are needed. Any new rate recovery device which would accelerate cost recovery of expensive high risk new technologies would be especially harmful to customers. It would be absolutely contrary to the goal of maintaining Kentucky's low cost advantage.

An additional financing option for pollution control facilities for the IOU and cooperative utilities in the form of securitization would be beneficial. Under appropriate circumstances, securitization can result in substantially lower environmental compliance costs. If any financing barriers do exist, then legislation authorizing securitization would be a full or at least partial solution.

RECOMMENDATIONS OF KIUC

1. Because IGCC technology is not currently economic or reliable it should be considered only if significant federal incentives are made available and if the utility needs new base load capacity.

2. No new rate recovery mechanisms or surcharges are needed for the utilities to continue meeting their public service infrastructure obligations.

3. Legislation should be enacted which gives utilities the option to finance pollution control equipment in the least cost manner through securitization.

4. The Commission should seek additional information on how the utilities plan to finance their projected major new capital additions.

5. Renewable energy resources should be required to meet least cost planning tests and should not be subsidized by ratepayers.

6. The issue of how Kentucky's two largest power users (Alcan and Century) will be reliably served at fair, just, reasonable and non-discriminatory rates after their contracts expire in 2010/2011 is complex and needs additional examination.

Respectively submitted,

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COUNSEL FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

June 7, 2005

APPENDIX A

EPRI

Financial Incentives for Deployment of IGCC: A CoalFleet Working Paper

Prepared for the

Senate Committee on Energy & Natural Resources

Bipartisan Coal Conference

March 10, 2005

Washington, DC

About This Paper

This working paper is an evolving document that summarizes the key insights from CoalFleet incentives analyses. The underlying philosophy of the analyses is to illustrate how a range of companies might value Federal incentives.

This version (March 10, 2005) of the paper, which focuses on IGCC deployment incentives, is undergoing internal and external review. Specifically:

- We continue to review financial analysis methods with a broad range of companies (investor-owned utilities, independent power producers, and public power entities) to ensure that our basic approaches are consistent with how they would evaluate IGCC versus a more conventional pulverized coal plant.
- We have initiated a coordinated effort with DOE's Office of Policy to examine incentive value using their financial models and to estimate the cost of incentives to the government.
- We have initiated an outreach effort to review and discuss our initial results with other research groups.

Next steps include examining additional incentives and examining similar issues for other advanced coal technologies.

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CoalFleet for Tomorrow is an industry collaborative formed to accelerate the deployment and commercialization of clean, efficient advanced coal power systems, thereby preserving this abundant fuel option as a vital component of our nation's and the world's energy mix. The CoalFleet initiative addresses the technical, economic, and institutional challenges to making advanced coal power plants a prudent investment option in both the short and long term, while taking into account the potential for future CO_2 emission regulations.

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California, and Charlotte, North Carolina, was established in 1973 as an independent, non-profit center for public interest energy and environmental research. EPRI brings together member organizations, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of power generation, delivery and use, including health, safety and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents over 10% of EPRI's total R&D program.

EPRI

Financial Incentives for Deployment of IGCC: A CoalFleet Working Paper

Executive Summary

Integrated gasification combined cycle (IGCC) is an electric generating technology that gasifies coal, uses the gas to power a combustion turbine to generate electricity, and uses the turbine's waste heat to generate additional power. IGCC promises higher thermal efficiency and lower air pollution emissions than conventional coal-fired power plants (PC), as well as the potential for being able to produce a concentrated waste stream of CO_2 that could be captured and sequestered in geologic formations. IGCC has been used in a number of U.S. demonstration facilities but as yet has not been commercially deployed in the United States because of its higher capital cost and technology risk.

This paper presents EPRI's analysis of the effectiveness of eight alternative Federal financial incentives that have been proposed to mitigate IGCC's higher costs and risks. The intent of these incentives is to lessen the cost differential between IGCC and conventional coal technologies so that an initial set of IGCC plants will be deployed, allowing future experience-based reductions in cost and improvements in performance that could make IGCC commercially viable. The incentives analyzed include: loan guarantees, direct Federal loans, Federal cost sharing grants, investment tax credits, production tax credits, tax-exempt financing, accelerated depreciation, and Federal availability insurance. The analysis looks at the usefulness of each incentive for three types of project owners: regulated investor-owned utilities (IOUs), independent power producers with a power purchase agreement (IPPs), and public power (including cooperative, Federal, municipal, and state entities).

The analysis compares the cost of an IGCC plant with the cost of a conventional supercritical PC plant in terms of cost of electricity (COE) – that is, the levelized cost of electricity produced from a generating unit over a 30-year period. COE is a useful method for comparing the costs of competing coal technologies, both for asset owners and utility customers. The analysis indicates that, without incentives, COE for IGCC units significantly exceeds COE for conventional coal units. This "COE gap" is in the 17-19% range. About half the COE gap is attributable to higher capital costs. The other half is attributable to technology risk – the risk that the unit will not attain design levels of performance, as shown in Table A.

Table A. COE Gap Without Incentives ($/MWh)

COE Gap (IGCC – PC)	IOU	IPP	Public/Coop
Capital Cost Gap (without technology risk)	$ 3.90	$ 4.43	$ 2.70
Technology Risk COE Gap	$ 4.00	$ 3.34	$ 2.71
Total COE Gap	**$ 7.90**	**$ 7.77**	**$ 5.41**

The incentives examined (shown in Table B) have varying value to different project owners. For example, while tax incentives may have significant value to profitable IOUs and IPPs, they have no value (unless they are tradable) to public entities. Given our assumptions, none of the incentives studied are individually sufficient to bridge the COE gap faced by the various prospective project owners.

Table B. Value of Base Case Incentives Compared With COE Gap ($/MWh)

	IOU	IPP	Public/Coop
Loan Guarantee with No Fee	$ 1.08	$ 1.80	$ 0
Direct Loan	$ 3.24	$ 6.76	$ 0
Cost Sharing Grant (10% without repayment)	$ 2.08	$ 2.17	$ 1.54
Investment Tax Credit (ITC) (10%)	$ 2.29	$ 2.37	$ 0
Production Tax Credit	$ 4.24	$ 4.23	$ 0
Tax Exempt Financing	$ 2.97	$ 4.85	$ 0
Accelerated Depreciation	$ 3.14	$ 3.33	$ 0
Availability Insurance (at 78% actual availability)	$ 0.90	$ 1.02	$ 0.82
IGCC – PC COE Gap	*$ 7.90*	*$ 7.77*	*$ 5.41*

While none of the base case incentives are sufficient to fill the COE gap, combining several incentives or scaling them up can reduce or eliminate this gap. Table C borrows from existing proposals and from legislation for other energy sources to provide several examples of how incentives can be tailored to do so: (1) combining a scaled-up, 20% investment tax credit (ITC) with accelerated depreciation, (2) an enhanced production tax credit (PTC) equal to the current wind PTC, and (3) combining a 30% Federal cost-sharing (with no repayment required) and availability insurance. While different project owners are likely to value the incentive packages somewhat differently, these estimates provide useful insight into how incentives could be tailored to bridge the COE gap for all three types of companies.

Table C. Value of Tailored Incentives Compared With COE Gap ($/MWh)

	IOU	IPP	Public/Coop
20% ITC + Accelerated Depreciation	$ 7.72	$ 7.06	$ 0
Wind Energy PTC ($18/MWh)	$ 8.48	$ 8.46	$ 0
Cost Share (30% without repayment) + Availability Insurance	$ 6.25	$ 6.51	$ 5.44
IGCC – PC COE Gap	*$ 7.90*	*$ 7.77*	*$ 5.41*

This preliminary analysis provides a clearer view of the value of possible Federal incentives for encouraging initial deployment of IGCC for companies considering new coal-based generation options. It does not address refueling of existing combined cycle units with syngas, the economics of potential non-electric products of gasification, or the use of other gasifier feedstocks such as petroleum coke and biomass. Also, at this time we do not address the cost of alternative incentives to the Federal government.

Financial Incentives for Deployment of IGCC: A CoalFleet Working Paper

I. INTRODUCTION

Gasifying coal to produce electricity is an alternative to the traditional method of directly burning coal in pulverized coal (PC) facilities. This process is referred to as Integrated Gasification Combined Cycle (IGCC). In coal gasification, a gasifier reacts the coal with steam and controlled amounts of air or oxygen under high temperatures and pressures. The heat and pressure break apart the chemical bonds in the coal's molecular structure, setting into motion chemical reactions with the steam and oxygen to form a gaseous mixture, called a synthesis gas (or syngas), made up primarily of carbon monoxide and hydrogen. The syngas is then combusted in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators (hence the term "combined cycle").[1] IGCC provides higher thermal efficiency than current PC plants, lower emissions, and the potential for carbon capture and sequestration. (See discussion below in part II.)

There are four coal-fired IGCC facilities in operation today.[2] Two of these are demonstration facilities located in the United States – the Tampa Electric IGCC facility located in Florida (GE/ChevronTexaco gasifier) and the Wabash River Coal Gasification Repowering Project located in Indiana (E-Gas™/ConocoPhillips gasifier). The other two are located in Europe.[3]

Although gasifying coal is a commercially proven process and is used throughout the world in developing chemicals, fuels, and other by-products, the integration of coal gasification with a combined cycle power block to produce electricity is a relatively new technique and involves an operational complexity beyond that experienced with PC plants. And while operational at near commercial-scale (250 to 300 MW in size), each of the existing IGCC units has encountered various technical and operational impediments relating to the reliability of the system. For IGCC to be cost competitive in the retail electricity market, IGCC plants will likely need to be available for power production in the range of 80-90% of the hours in a year. However, these existing IGCC demonstration projects have failed to consistently achieve this target without a spare gasifier. While use of a spare gasifier significantly improves the availability of an IGCC plant, the use of a spare also increases the capital cost of the plant. Another limitation is that current gasifier technology is only proven to be cost effective with bituminous coals.[4]

II. POTENTIAL BENEFITS OF IGCC TECHNOLOGY

The IGCC process increases the efficiency of the overall system by using the waste heat from the combustion turbine to produce steam to drive the steam turbine. Existing commercially available IGCC systems are expected to achieve a thermal efficiency of approximately 39-41%.[5] In comparison, the existing fleet of pulverized coal facilities in operation in the U.S. today is generating electricity with an average thermal efficiency of about 33%.[6] With further advances in gas turbine technologies, it is believed that IGCC systems are capable of reaching efficiencies of 45-50%. Hence, IGCC provides a new, potentially competitive coal-fired electricity generation option. More importantly, deployment of IGCC units would provide significant energy security, fuel diversity, and environmental benefits.

Energy Security and Fuel Diversity. Coal is the nation's most abundant domestic energy resource but low natural gas prices and uncertainty as to future environmental limitations on coal use have constrained construction of new coal-fired generation units. Since 1990, only about 15 GW of new coal-fired capacity has been completed in the United States. By contrast, about 200 GW of new natural gas capacity has been placed in service in the same period. Because of IGCC's capability to reduce conventional emissions and its carbon capture potential (see below), widespread deployment of IGCC units offers the prospect of retaining or even increasing coal's place in the power generation market. In some cases, efficient coal gasification equipment could be used to repower existing gas combined cycle units, directly displacing natural gas use. Increased use of coal could take some of the pressure off of natural gas prices, which have more than doubled since early 2000 and are forecasted to remain relatively high.

Air Quality Benefits. If widely deployed, IGCC promises substantial air quality and public health benefits. Because pollutants can be separated from the gaseous stream before combustion of the syngas, IGCC systems can achieve very low emissions of conventional air pollutants, such as sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter, and mercury. A state-of-the-art IGCC unit can remove as much as 99% of sulfur and 90-95% of mercury.[7]

Potential Climate Change Benefits. An important feature of the IGCC system is that carbon monoxide in the synthesis gas can be reacted with steam to make hydrogen and carbon dioxide (CO_2). This creates the potential to separate a relatively pure stream of CO_2, which can feasibly be "sequestered" in geologic formations, thus avoiding its emission into the atmosphere.[8] IGCC's carbon capture capability provides a useful hedge against regulatory uncertainty, should policy-makers decide to impose binding limitations on CO_2 emissions in the future.

Table I compares the performance of (i) new conventional PC units (based on the design parameters of new super-critical units currently in the permitting stage) compared with the expected performance of (ii) current IGCC units (those likely to be deployed were Congress to adopt a financial incentives program), (iii) near-future IGCC technology (units built after the initial units were deployed), and (iv) 2020 IGCC (the performance targets under the DOE/CURC/EPRI roadmap [http://www.coal.org/content/roadmap.htm]). To simplify comparison, emissions of conventional pollutants are shown in terms of tons (or pounds) per year from a standard 550 MW unit that operates at an 85% capacity factor.

Table I. IGCC and PC Performance

Performance Characteristic	New Conventional PC [a]	IGCC Current	IGCC Near-Future	IGCC 2020
Thermal Efficiency [b]	38.6 %	39.7 %	40.6 %	45 %
Sulfur Dioxide (SO_2) (tons/year)	3,027	566	276	250
Oxides of Nitrogen (NO_X) (tons/year)	1,412	1,094	219	198
Mercury (Hg) (lbs./year)	45	29	29	26
Carbon Dioxide (CO_2) (million tons/year)	3.7	3.6	3.5	3.2
Potential for Carbon Capture and Sequestration	Limited	Yes [c]	Yes [c]	Yes [c]

a. Based on performance of supercritical units currently undergoing environmental permitting. Advanced combustion technologies, such as ultra-supercritical pulverized coal boilers, may ultimately demonstrate performance characteristics similar to IGCC.

b. Thermal efficiency based on Pittsburgh #8 coal – data from EPRI.

c. Extent of carbon capture depends on facility design.

Table I indicates that the IGCC units that are initially deployed are likely to have somewhat higher efficiency and significantly lower emissions than conventional PC units with emission controls. The SO_2 and NO_X emissions from the near-future IGCC technology will be less than 20% of the already low levels of the PC unit. Mercury reductions and efficiency gains would also be significant. IGCC units would emit less CO_2 due to their higher thermal efficiency and provide a much less expensive option for carbon capture than current PC units. 2020 targets for IGCC show major improvements in thermal efficiency resulting in further reduction in all pollutants.

III. BARRIERS TO IGCC DEPLOYMENT

Despite the significant technological advantages of the IGCC technology—low emissions, high efficiency, and potential for carbon capture and sequestration—IGCC has not been commercially deployed in the U.S. or elsewhere. Low natural gas prices were a key reason for this in the 1990s. Today, two principal factors account for this: higher initial capital costs for IGCC, and industry concern that commercial-scale IGCC units pose technological risks that impact the reliability and availability of the unit.

There are significantly higher costs associated with building an IGCC facility when compared to the costs associated with constructing a traditional pulverized coal facility. According to EPRI data, the capital cost of an IGCC unit—in terms of $ per kW of generating capacity—is about 14% higher than a conventional pulverized coal unit. This accounts for about half of the estimated 17-19% differential in the cost of electricity between a PC unit and an IGCC unit. (See Table III in Section VI.) Due to their significantly higher capital cost, the four IGCC units in operation today were built with partial government funding.

Technology risk—that is, the risk that full-scale units in commercial service will not have a level of performance at least equivalent to pulverized coal units—is an equally serious barrier to IGCC commercial deployment. A particular concern is the question of whether the unit's availability, its ability to run continuously at full power without breakdowns, is equivalent to that of a conventional coal unit. Because of this perceived risk, the financial community imposes a risk premium on IGCC, limiting its market penetration absent some kind of financial incentive. IGCC facility design that includes a spare gasifier can mitigate part, but not all, of this risk.

Technology risk presents a particularly difficult challenge. As utilities and other entities undertake the commercial deployment of IGCC projects, they face numerous other risks—such as market price risks respecting their fuel supply and electric output, cost overrun risks, and regulatory and political risks—but these are not qualitatively different from risks that any company runs in building a conventional coal-fired power plant. For most of these risks there are commercially available instruments to mitigate these risks, including long-term fixed price fuel supply and power purchase contracts, fixed price engineering, procurement and construction (EPC) contracts, and various types of hedging contracts. What is not commercially available at reasonable cost, however, is an instrument for mitigation or hedging of technological risks. As a result, companies contemplating commercial deployment of IGCC technology face not only higher capital costs, but also technological risks that are likely to affect output and performance and cannot be hedged in today's marketplace at reasonable cost.

The remainder of the paper reviews the effectiveness of a number of Federal financial incentives that have been proposed as means to reduce the cost differential between IGCC and conventional PC technologies and to mitigate the technology risk associated with IGCC.[9] These incentive mechanisms include loan guarantees, direct loans, Federal cost sharing, four types of Federal tax incentives (investment credit, production credit, accelerated depreciation, and tax exempt financing), and Federal availability insurance. They are described below. The effectiveness of these incentives is reviewed for three classes of project owners: regulated investor-owned utilities (IOUs), independent power producers (IPPs), and public power/cooperatives. The incentive mechanisms are described in Section IV, and their usefulness to each class of project owner is discussed in Section V.

Attachment B to this paper addresses the question of how the Federal government analyzes the budgetary costs of the various incentives. Our analysis does not address this question at this time.

IV. TYPES OF FEDERAL FINANCIAL INCENTIVES

A. Federal Loan Guarantees

DOE and other agencies have been authorized under a number of different statutes to provide loan guarantees for development and commercial demonstration of advanced energy technologies. Loan guarantees permit a project sponsor to obtain debt financing at an interest rate closer to the Federal government's cost of money. In addition, a loan guarantee may permit a highly leveraged capital structure for the IGCC project – substituting low cost debt for high cost equity. Non-recourse loan guarantees can also shift a portion of a project's technology risk to the Federal government.

A useful example is DOE's authority under section 19 of the Federal Non-Nuclear Energy Research and Development Act of 1974 (the "Federal Non-Nuclear Act") which authorizes DOE to guarantee principal and interest on loans for construction and startup of "demonstration facilities" to produce alternative fuels from coal or other fossil fuel. The guarantee may not exceed 75% of projected project cost (60% for cost overruns), and the term of the obligation that is guaranteed cannot exceed 20 years (or 90% of useful life, if less).[10]

B. Direct Loans

Under a direct Federal loan program, the Federal agency—generally through the Federal Financing Bank—makes a long-term loan to the project owner to cover a portion of the cost of the facility. Interest rates vary depending on the program but are generally close to those on Treasury obligations of comparable terms.

C. Federal Cost Sharing

DOE and other agencies enter into a wide variety of cost sharing arrangements under which the Federal agency contributes a percentage of the capital cost of a commercial demonstration project. A current example of a cost-sharing program is DOE's Clean Coal Power Initiative (CCPI). Initiated in 2002, CCPI is a government/industry cost-shared technology demonstration program to foster more efficient clean coal technologies (CCTs) for use in new and existing electric power generating facilities in the United States. Candidate technologies are demonstrated at full-scale to ensure proof-of-operation prior to commercialization. DOE selects CCPI projects proposed by industry based on criteria in its financial assistance solicitation. The non-Federal cost share must be at least 50% of the total allowable cost of the project. Cost sharing may be in various forms or combinations, including cash outlays, and in-kind contributions. The government is under no obligation to share any cost overruns.

Applicants are required to repay 100% of the DOE actual contribution to the project upon successful commercialization of the technology being demonstrated. Repayment may come from various revenue streams including those from the demonstration project itself, royalties from sales and licensing of the demonstration technology in the United States and abroad, and/or any other source of funds the applicant chooses to propose.

D. Investment Tax Credit

Investment tax credits under the Internal Revenue Code provide the taxpayer a credit against regular income tax otherwise due, based on a percentage of taxpayer investment in specified equipment and facilities. The investment tax credit is one of 18 business tax credits that are available to corporations and other business taxpayers.[11] The investment tax credits under the current Code are 10% for certain capital investments in energy property, reforestation and rehabilitated buildings.[12] "Energy property" is limited to solar and geothermal equipment and facilities.[13]

Under current law, the use of the investment tax credit and most other business credits is constrained by a number of important limitations. First, the investment tax credit (along with the other business tax credits) may not exceed 25% of regular tax otherwise due.[14] Thus, a taxpayer who has no tax liability because of an unprofitable year will be unable to use the credit in the year in which it is earned. In addition, if the taxpayer reaches the 25% limit through use of other credits, the additional IGCC credit will not be useable in the current year.[15] Second, the investment tax credit and other business credits are not generally allowable against the alternative minimum tax (AMT).[16] (The AMT imposes a supplemental tax on taxpayers who make intensive use of tax preferences, such as accelerated depreciation, percentage depletion.)[17] Thus, to the extent a company pays AMT rather than regular tax in a taxable year, under the Code's general rules, an investment tax credit will not provide it any benefit in that year.[18] Third, as a general rule, under the Code, business tax credits are usable only by taxpaying entities.[19] Municipal utilities and state power agencies cannot take advantage of them. Most cooperative utilities are also tax-exempt and unable to use business credits.

E. Production Tax Credit

A production tax credit provides the taxpayer with a credit against income tax otherwise due based on the amount of energy actually produced from a facility, rather than on the capital cost of the facility. Under current law, a 1.8¢/kWh production tax credit is available for certain renewable electricity production, including wind, biomass, geothermal, and solar.

In the context of IGCC, a key difference between the production tax credit and the investment tax credit is that with a production credit, the Federal government assumes none of the technology risks of the project – the production credit is allowable only to the extent the facility actually produces electricity. An investment tax credit, by contrast, is available without regard to the level of performance of the facility, so long as it has been placed in service.

The production tax credit is also subject to various structural limitations on the usability of the credits (discussed above in the context of the investment tax credit), including unavailability to state and local governments and most cooperatives, the limitation based on the amount of tax and AMT limits.

F. Tax-Exempt Financing

The general rule under the Code is that interest paid on obligations issued by state and local governments is exempt from Federal income tax, subject, however, to exceptions relating to private activity bonds (sometimes referred to as "industrial development bonds"). Under the private activity bond rules, obligations issued by a state or local government primarily for the benefit of a non-governmental entity are generally not tax-exempt. The Code, however, permits tax-exempt industrial development bonds for the benefit of private sector companies for particular purposes such as airports, local furnishing of electric and gas, district heating and cooling, and high-speed rail. Also, during the 1970s, tax-exempt industrial development bonds could be issued to finance investor-owned utilities' pollution control facilities. A similar provision for IGCC projects would lower interest rates and capital costs for IOUs and IPPs.

G. Accelerated Depreciation

The Code allows a deduction against gross income for depreciation, and specifies various methods for computing the allowance for depreciation. Moving an asset into a category that provides for a shorter recovery period (i.e., shorter tax life), or which permits most of the depreciation to be taken in early years of the recovery period, increases the value of the depreciation deduction.

As with other tax incentives, accelerated depreciation provides no direct benefit to entities that are exempt from tax, nor any near-term benefit to unprofitable or startup companies who cannot use the deduction.

H. Availability Insurance

Federal availability insurance is a new concept which has not been spelled out in detail in legislation as of this time. Our analysis assumes an insurance program under which DOE issues availability insurance to the owner of a proposed IGCC project to cover a portion of the economic loss resulting from the project's not meeting its design availability target during its first ten years of commercial service. The project's design availability target would be specified in the insurance agreement, but could not exceed average annual availability of U.S. pulverized coal units equipped with FGD and SCR during the preceding 5 years. The economic loss covered in any year by the Federal insurance would be equal to project debt service multiplied by the percentage by which the unit misses its design availability target in a year. Not covered would be unavailability by reason of (i) force majeure, (ii) failure to follow good utility practice or applicable maintenance or warranty requirements, or (iii) defects of material or workmanship.

I. Other Incentives

Other incentives could be considered for IGCC (e.g., price guarantees). Price guarantees, however, are principally useful for mitigating market risk rather than technology risk and are not considered in the analysis.

V. USEABILITY OF INCENTIVES FOR PROJECT OWNERS

IGCC project owners have different credit standings, exposures to regulation, and sources of financing. Regulated investor-owned utilities, for example, use taxable debt and equity financing from non-governmental sources, generally have good credit standing but are subject to rate-of-return regulation. Municipal utilities, on the other hand, are not-for-profit, are unregulated, have good credit standing, and have access to low-cost tax exempt financing. Independent power producers use taxable financing, they are unregulated, and—at present—many have shaky credit standing at the corporate level, but have better credit standing at the project level for projects backed by a long-term power purchase contract. Because of these differences, the value of a particular incentive mechanism will vary depending on the type of entity that is proposing an IGCC project. This section describes some of the key factors that are significant in determining the value of particular incentives to different classes of project sponsors.

A. Regulated Investor-Owned Utilities

Electric utilities in about half of the States are regulated on a cost-of-service basis – that is, State regulatory commissions permit them to recover prudently-incurred operating expenses and a reasonable rate of return on prudently-incurred costs of facilities that are "used and useful" in providing utility services. The prudence and "used and useful" requirements mean that a utility that incurs higher capital cost for an IGCC unit than it would for a pulverized coal unit of the same size is at risk of not recovering that cost increment in its retail rates. Regulators may also disallow costs incurred to purchase replacement power if the unit is not available for power production to the same extent that a conventional coal unit would be. A utility in these circumstances will seek advance approval from its regulators before proceeding with the project. The effect of the advance approval, if it is obtained, is to transfer much of the incremental capital cost and unavailability risk to the ratepayers. However, approval is not likely to be forthcoming if the capital cost increment or unavailability risk is unacceptably high. Thus, both utilities and regulators are likely to look for financial incentives that buy down the upfront capital costs of IGCC and, if possible, mitigate technology risks. Utilities, unlike other companies, are not in the position to bear the technology risk in return for higher potential returns since their regulators strictly limit their rate of return on equity.

Federal cost sharing and investment tax credits may be particularly useful to regulated utilities because they are an effective means of reducing upfront capital cost, and will have value even if the technology does not perform as expected. (By contrast, a production tax credit is useful only to the extent the unit is available and is run to produce power.[20]) Loan guarantees on the other hand are not particularly useful to regulated utilities that, for the most part, have good credit standing and are not likely to benefit significantly from a highly leveraged IGCC project financing. A utility with a typical credit rating can obtain debt financing at interest rates that are about 1.5% above the Treasury's for obligations of similar maturity. And while more highly leveraged project financing arguably may lower the overall capital-related costs of an IGCC unit (by substituting low cost debt for higher cost debt) this reduction is estimated to be only about 0.5%, and will not result in a significant reduction in COE. For that reason, loan guarantees are not attractive to most utilities.

B. Independent Power Producers and Other Unregulated Firms

Independent power producers, utilities not regulated on a cost-of-service basis and other unregulated firms that are owners of IGCC units[21] can use a set of financial incentives that are much different than those that are useful to regulated utilities. These firms differ in important respects from regulated investor-owned utilities. First, in many cases they have lower credit standing than regulated utilities, and thus have more use for Federal loan guarantees or direct loans. Our analysis assumes that IPP facilities are project-financed and that the projects have long-term power purchase contracts. Second, they may not have taxable income at the time they become entitled to a tax credit (or other tax incentive), and thus may not able to use tax credits (or other tax incentives) until they become profitable. Third, they have no regulatory limitations on rate of return, and thus may be able to accept more technology risk because of the possibility that a successful project may be highly profitable.

For these entities, loan guarantees may be a useful incentive, providing some interest rate and leverage benefits and, perhaps as importantly, improving terms and availability of financing. Direct loans provide much more value, with the government supplying a lower interest rate and better terms than would be available in the private market. Tax incentives can be useful to profitable firms, and Federal cost sharing can be useful for firms that have access to capital to finance the non-Federal share.

C. Public Entities and Cooperatives

Public entities in this analysis include Federal, municipal, and state-owned entities. These entities are not-for-profit, generally unregulated, and for the most part highly creditworthy. For a highly creditworthy municipal issuer, for example, tax-exempt financing provides capital at interest costs lower than the Treasury's, and well below the cost of capital for most investor-owned utilities.

Customer-owned electric cooperatives are also not-for-profit, but are subject to rate regulation in about one-third of the states. Cooperatives that qualify for financing under the Rural Electrification Act have access to direct loans from the Federal Financing Bank at interest rates close to Treasury rates. Cooperatives that are taxable often distribute income to members in ways that leave them with no tax liability. For the purposes of incentive analyses they can be treated as tax-exempt.

Creditworthy municipal utilities are unlikely to use loan guarantees, since their cost of capital is already below the Federal government's. Cooperative utilities are also unlikely to benefit from using loan guarantees as they have access to Federal Financing Bank funding through the Rural Utilities Service at interest rates comparable to the government's rates. As noted above, municipal utilities and most cooperative utilities are tax exempt and therefore unable to benefit from investment or production tax credits or accelerated depreciation.

Tax-exempt financing does not provide a useful incentive to municipal utilities, since they already have access to tax-exempt financing. Nor would it be particularly useful for cooperatives that have access to the Federal Financing Bank at interest rates that are equivalent to the Federal government's cost of money.

The incentives that can be useful to municipal and cooperative utilities are Federal cost sharing (where the Federal government subsidizes a portion of the capital cost of the facility) and performance guarantees (which reduce the technology risk otherwise borne by the utility).

VI. EFFECTIVENESS OF FEDERAL FINANCIAL INCENTIVES IN STIMULATING DEPLOYMENT OF IGCC

To determine the effectiveness of alternative incentive mechanisms, we first calculate the "COE gap" – that is, the extent to which the cost of electricity (COE) produced by an IGCC plant exceeds the COE from a conventional supercritical PC plant. This cost of electricity calculation takes into account capital costs (debt and equity), thermal efficiency, fuel and other operating costs, capacity factors (i.e., the extent to which the unit actually produces power in a year), and technology risk.

The costs associated with technology risk were estimated by assuming that initially deployed IGCC units will have availability consistent with the experience of the two U.S. demonstration projects.[22] Thus, IGCC has a lower availability than PC, which results in a decrease in capacity factor from 88% (for PC) to 78% (for IGCC). This lower capacity factor increases the COE by spreading the fixed costs over fewer MWhs.

Table XIV (in Attachment A) compares key parameters for cost and performance of current PC and IGCC technology (for initially deployed units) used in its COE analysis. Table XV (also in Attachment A) details key financial assumptions for the IOU, IPP, and Public power entities/cooperatives. The results of the COE analysis appear in Table II, and the computation of the COE gap in Table III.[23]

Once the COE gap between PC and IGCC is determined, the effectiveness of the incentive mechanisms in closing the gap is estimated. This analysis is done for the eight incentive mechanisms (loan guarantees, direct loans, cost sharing, the four tax incentives, and availability insurance) as applied to each of the principal classes of project owners – investor-owned utilities, independent power producers, and public power/cooperative. The results of the analysis appear in Tables IV-XI.

A. Determination of COE Gap

Table II shows the comparative COE measures for IGCC and PC plants for the three classes of project owners. The COE estimates differ by ownership for a number of key reasons. First is the debt structure. Based upon typical industry practices, the IOU is assumed to use corporate financing with 55% debt. The IPP with a PPA is assumed to use project financing and achieves a higher leverage of 70% debt. Public power entities and cooperatives are assumed to use 100% debt financing. The next key factor is the cost of debt. Because the financial markets believe that the IPP has higher risk, it is assumed to demand higher return on equity (13% versus 11.5% for the IOU) and debt (8% versus 6.5% for the IOU). The Public entity's debt is not taxable to bond holders (for municipals), so the assumed interest rate is only 4.5%. In addition, the cost of the electricity depends upon tax treatment of income and expenditures. The IOU and IPP are assumed to pay both Federal and state taxes on income, with a combined rate of 39.2%. The public entity and cooperative are either non-taxable or do not pay taxes.

The COE cost of the IGCC plant is calculated with and without technology risk by examining two scenarios for plant availability. In one case, the IGCC plant is assumed to operate as designed by the end of its third year in service, averaging 88% availability over 30 years. In the technology risk case, the plant is assumed to operate more consistently with current IGCC experience, averaging 78% availability over 30 years. This technology risk case yields a higher COE since it spreads the same fixed costs over fewer MWh of generation.

These analyses of COE and our analyses of incentive value assume no electricity market risk.

Table II. COE Without Incentives ($/MWh)

COE ($/MWh)	IOU	IPP	Public/Coop
Supercritical PC	$ 41.11	$ 41.13	$ 32.13
IGCC Without Technology Risk (88% capacity factor)	$ 45.01	$ 45.56	$ 34.83
IGCC With Technology Risk (78% capacity factor)	$ 49.01	$ 48.90	$ 37.53

Table III shows the estimated COE Gap. The cost difference between PC and IGCC without technology risk is largely attributable to IGCC's capital cost and is referred to as "Capital Cost Gap." The difference that is attributable to technology risk is referred to as "Technology Risk COE Gap." The sum of the two is referred to as "Total COE Gap." It is Total COE Gap that the Federal incentives are intended to bridge in order to permit the IGCC technology to be deployed.

Table III. COE Gap Without Incentives ($/MWh)

COE Gap (IGCC – PC)	**IOU**	**IPP**	**Public/Coop**
Capital Cost Gap (without technology risk)	$ 3.90	$ 4.43	$ 2.70
Technology Risk COE Gap	$ 4.00	$ 3.34	$ 2.71
Total COE Gap	**$ 7.90**	**$ 7.77**	**$ 5.41**

B. Determination of Value of Incentives

The estimated value of each incentive mechanism in reducing the COE gap is described below, together with key assumptions that underlie the analysis. It should be noted that the objective of the analysis is to estimate the value of the incentive mechanisms for representative entities in each owner class – the value of the incentives to a particular entity will, of course, depend on the financial circumstance of that entity and the specific terms in which the incentive is offered.

Loan Guarantees: The value of the loan guarantee incentive depends on the fraction of the plant cost that receives the guarantee and the reduced interest rate on the guaranteed loan. The yearly interest saving is the interest rate reduction times the outstanding debt during both construction and operation. These savings are present valued and then levelized across the unit's production to determine the value of the incentive.

Based upon discussions with companies that deal with a broad range of Federally-guaranteed debt instruments, we have assumed interest rate savings would be 0.5% for the IOU and 0.8% for the IPP w/PPA. In both cases, the guarantee reduces the interest rate – but not to the rate for long-term Treasury bonds (T-bond rate) because even though the U.S. Government pays back the lenders in the event of default, delays, prepayment, and transaction costs make lenders demand a rate above the T-bond rate. Even without considering default, amortization and transactions costs lower the attractiveness to investors when comparing this offering to purchase of a T-bond. (The actual interest rate savings will depend upon the details of the legislation and market conditions when the loan is sought. The best case would be if the legislation were written so the asset owner could borrow directly from the government at, or close to, the T-bond rate. This case of a "direct loan" is modeled below.)

We assume that the loan guarantee covers up to 80% of the facility cost. We examine two debt-fraction cases for the IOU and IPP when they are offered this guarantee. In the first, they increase their debt fraction to 80%, receiving the interest rate savings across this 80% debt (note that the IOU would very likely lower debt fractions on other projects in order to maintain their traditional overall corporate debt structure). In the second case, we assume that they retain their more typical debt fractions for the IGCC project, receiving interest rate savings for a smaller amount of debt. In this second case, the IOU is assumed to finance 55% of the facility cost (corporate financing) at the lower interest rate; the IPP with a power purchase agreement is assumed to finance 70% (non-recourse project financing) at this lower rate.

The estimated values of the incentive for each company type and debt fraction assumption appear in Table IV. The value of the loan guarantee is expected to be small for IOUs. The value to Public/Coop power owners is zero because they currently borrow at rates equal to or lower than the T-bond rate. The estimated value to the IPP may be somewhat greater than shown. While it includes the assumed interest rate savings and advantage of increased debt leverage, it does not include an explicit consideration of the value of improved borrowing terms, longer tenor, and expanded pool of possible investors, all of which could provide significant value to a project-based finance deal.

The estimates in Table IV do not include the cost of possible up-front loan fees. We have not estimated the cost of this program to the government and have no detailed analytical basis for estimating this loan fee. As a point of reference, an up-front loan fee of 3% of total project cost[24] would reduce these values by about $0.80/MWh.

Table IV. Value of a Loan Guarantee ($/MWh) With No Up-Front Fee

	IOU	IPP	Public/Coop
Base Case (increased debt fraction to 80%; interest rate reduced by 0.5% for IOU and 0.8% for IPP)	$ 1.08	$ 1.80	$ 0
Reduce Interest Rates as in Base Case; Maintain Typical Debt Fraction	$ 0.74	$ 1.58	$ 0

Direct Loans: This case analyzes Federal direct loans for 80% of project cost, available at the same interest rate as the 30-year T-Bond. Interest rate savings of 1.5% are assumed for an IOU and 3% for an IPP. As with loan guarantees, the value to public power owners is zero.

Table V. Value of Direct Federal Loan ($/MWh)

	IOU	IPP	Public/Coop
80% Direct Loan	$ 3.24	$ 6.76	$ 0

Federal Cost Sharing: The cost sharing percentage is assumed to be 10%. Cost sharing is assumed to be available during construction. The results are shown in Table VI. The base case assumes that the owner does not pay back the cost sharing. If the owner pays back the government over the first twenty years of plant operation, the value of the incentive drops. The value of these cost-sharing incentives scales with the percentage of the cost share. A 20% cost sharing grant would provide twice the values shown in Table VI. Also, the value can be increased or decreased somewhat depending upon the precise terms and timing of repayment.

Table VI. Value of 10% Federal Cost Sharing Grant ($/MWh)

	IOU	IPP	Public/Coop
Base Case (no pay-back)	$ 2.08	$ 2.17	$ 1.54
Pay Back Over 20 Years (no interest)	$ 1.00	$ 1.04	$ 0.33

Investment Tax Credit: The investment tax credit (ITC) is assumed to be 10% of the plant cost. The ITC becomes available to the owner at plant startup. The results of the incentive are shown in Table VII. Since public power owners do not pay tax, the incentive is worth zero. If the company is able to use all of the ITC to reduce current tax liability, the value of the incentive scales with the size of the ITC; the 20% case has twice as much incentive value. A larger ITC increases the probability that some of the tax benefits from the credit might be received in later years. If, for example, the tax benefits are delayed five years on average, the credit would be worth about 25% less to an IOU or IPP. This issue of when the credits can be used is similarly important for the production tax credit and accelerated depreciation.

Table VII. Value of ITC ($/MWh)

	IOU	IPP	Public/Coop
Base Case (10%)	$ 2.29	$ 2.37	$ 0
20% ITC	$ 4.58	$ 4.74	$ 0

Production Tax Credit: The production tax credit (PTC) rate is $9/MWh for the first ten years of the plant operation. The results appear in Table VIII. Again, the value of the incentive (in $/MWh) scales with the PTC amount.

Table VIII. Value of a $9/MWh PTC for 10 years ($/MWh)

	IOU	IPP	Public/Coop
Base Case – PTC ($9/MWh)	$ 4.24	$ 4.23	$ 0
Wind PTC Level ($18/MWh)	$ 8.48	$ 8.46	$ 0

Tax Exempt Financing: Tax exempt financing reduces the interest rate demanded by lenders. This reduction is applied to the outstanding bonds during construction and operation, present-valued to plant startup, and levelized over the project life. The interest rate is reduced by 31%, a figure implied by looking at the relative yields of non-taxable versus taxable debt instruments. The public owner already receives tax exempt status in this analysis (or borrows at the Treasury rate) and thus would receive no benefit from this incentive. Table IX shows the results.

Table IX. Value of Tax Exempt Financing ($/MWh)

	IOU	IPP	Public/Coop
Tax-Exempt Financing	$ 2.97	$ 4.85	$ 0

Accelerated Depreciation: Reducing the recovery period for tax depreciation provides the owner its income tax deduction for depreciation earlier in time. This time-value-of-money advantage translates into a lower COE when it is levelized. The base case reduced the twenty-year recovery period to the five-year period contained in recent legislation to stimulate investment. The results appear in Table X.

Table X. Value of Reducing the 20-Year Recovery Period to 5 Years ($/MWh)

	IOU	IPP	Public/Coop
Accelerated Depreciation	$ 3.14	$ 3.33	$ 0

Availability Insurance: Availability insurance is modeled by examining two scenarios for IGCC plant availability.[25] In one, it takes three years to reach the full design availability of 90%; the average availability over 30 years is 88%. In the other scenario, the plant is available 50% of time the first year, 60% the second, 70% the third and 80% thereafter; it never reaches its design availability and its average availability over 30 years is 78%.

The government is assumed to provide insurance for shortfalls below a negotiated availability target of 88%. The government insurance will cover a fraction of debt payment if a shortfall occurs, but does not provide any coverage of lost return on equity or fixed operating and maintenance costs. If the plant actually is available 78% of the time, insurance proceeds will cover about 16% of project debt service during the first 10 years of commercial operation. If the plant ramps quickly to 90%, the primary insurance needs will in the first two years of operation. Table XI shows the results. The insurance payment, as currently structured, falls well short of filling the $4/MWh technical risk COE gap but has the potential benefit that it is paid out only when needed based upon actual plant operation.

Table XI. Value of Availability Insurance ($/MWh)

	IOU	IPP	Public/Coop
4-Year Ramp Up to 80%	$ 0.90	$ 1.02	$ 0.82
3-Year Ramp Up to 90%	$ 0.29	$ 0.91	$ 0.21

VII. CONCLUSIONS

A. Summary of Relative Value of Incentives

Table XII shows the relative value of the various incentive mechanisms in bridging the COE gap (shown at the bottom of the table).

Table XII. Value of Base Case Incentives Compared with COE Gap ($/MWh)

	IOU	IPP	Public/Coop
Loan Guarantee with No Fee	$ 1.08	$ 1.80	$ 0
Direct Loan	$ 3.24	$ 6.76	$ 0
Cost Sharing Grant (10% without repayment)	$ 2.08	$ 2.17	$ 1.54
Investment Tax Credit (ITC) (10%)	$ 2.29	$ 2.37	$ 0
Production Tax Credit	$ 4.24	$ 4.23	$ 0
Tax Exempt Financing	$ 2.97	$ 4.85	$ 0
Accelerated Depreciation	$ 3.14	$ 3.33	$ 0
Availability Insurance (at 78% actual availability)	$ 0.90	$ 1.02	$ 0.82
IGCC – PC COE Gap	*$ 7.90*	*$ 7.77*	*$ 5.41*

B. Tailoring Incentives to COE Gap

No single incentive (as defined in its base case) provides enough COE value to make IGCC competitive with a PC. Table XIII borrows from existing proposals and other legislation to illustrate how incentives could be tailored to reduce or eliminate the COE gap between IGCC and the PC (shown at the bottom of the table). Every company would likely view the incentive packages somewhat differently, but these estimates provide insight into which are most likely to bridge the financial gap. The first tailored incentive combines a 20% ITC and accelerated depreciation. This package could make IGCC much more competitive for the two taxable entities. A second tailored incentive pays a production tax credit of $18/MWh, equal to the current wind energy PTC. This more than fills the COE gap for the two taxable entities. (A $15 to $17/MWh PTC would achieve a rough breakeven COE for IOUs and IPPs.) Finally, 30% Federal cost sharing without repayment combined with availability insurance could make all IPPs and publics essentially indifferent between the IGCC and the PC on a COE basis, and leave a small gap for the IOUs.

Table XIII. Value of Tailored Incentives Compared with COE Gap ($/MWh)

	IOU	IPP	Public/Coop
20% ITC + Accelerated Depreciation	$ 7.72	$ 7.06	$ 0
Wind Energy PTC ($18/MWh)	$ 8.48	$ 8.46	$ 0
Cost Share (30% w/o repayment) + Availability Insurance	$ 6.25	$ 6.51	$ 5.44
IGCC – PC COE Gap	*$ 7.90*	*$ 7.77*	*$ 5.41*

Attachment A

Table XIV. Key Cost and Performance Parameters: Conventional PC with SCR and FGD vs. Initially Deployed IGCC (2004$)

	Conventional Supercritical PC	IGCC (initially deployed units)
Capital Cost ($/kW) [a]	1,300	1,485 [b]
Dispatched Capacity Factor	88 %	78-88 % [c]
Thermal Efficiency Heat Rate	38.6 %	39.7 %
Variable O&M (non-fuel – $/MWh)	$ 1.60	$ 0.90
Fixed O&M ($/kW/Year)	$ 41.5	$ 58.1

a. Does not include 10% owner's cost or interest during construction.

b. Includes technology royalty; assumes spare gasifier. IPP is assumed to purchase private availability insurance for $60/kW, bringing its total capital cost to $1,545/kW. The $60/kW insurance price is calculated based upon the expected value of the insurance, rather than relying upon market data for this cost.

c. This calculation uses two availability scenarios, one reflecting design performance, one reflecting technological risk. The unit is assumed to be dispatched whenever it is available.

Table XV. Key Financial Assumptions for Different Project Owners

	IOU	IPP	Public
Fraction Debt	55 %	70 %	100 %
Cost of Debt	6.5 %	8 %	4.5 %
Cost of Equity	11.5 %	13 %	N/A
Tax Rate	39.2 %	39.2 %	0 %
Inflation Rate	2 % For All		

Attachment B

Cost of Incentives to the Federal Government

A. Budget Process

Any disbursement by the Executive Branch from the Treasury first requires an appropriation by Congress.[26] The Congressional Budget Control and Impoundment Act of 1974,[27] overlays this constitutional requirement with a complex set of rules that have important implications for an IGCC incentives program. That Act specifies that each year the Congress will set overall fiscal policy by enacting a Budget Resolution which provides the committees of Congress with their individual "budgets" to spend.[28] The Congressional Budget Act also provides that the Budget Resolution may require Congress to enact a Reconciliation Bill to change permanent law (such as entitlements, or existing taxes or fees) with extraordinary procedural advantages in the Senate (it requires only a majority vote to pass, thus it cannot be filibustered). To implement the Congressional budget process, Congress also created the Congressional scorekeeping system, run by the Congressional Budget Office (CBO), to determine whether costs and revenues under legislative proposals are consistent with budget ceilings. Finally, certain procedural safeguards were adopted—such as pay-as-you-go (pay-go)—that require that any losses in tax receipts, or increases in entitlement spending, would be "paid for" by corresponding increases in tax receipts or cuts in spending. Some of these safeguards expired in 2003. As of early 2005, the House had not reinstated the pay-go rule, but it is still in effect in the Senate.

Finally, the Anti-deficiency Act[29] prohibits Federal agencies not only from spending Federal funds not appropriated by Congress, but also from entering into any contracts the disbursements for which have not already been appropriated. However, there have been frequent statutory exceptions to this contracting limitation.

B. Scoring IGCC Incentives

Scoring translates a complex incentive program into a single cost number for Federal budgeting purposes. Scoring is relatively simple for incentives that involve direct spending – such as a Federal cost sharing program. Budget authority is equal to the amount of the appropriation required for the program. In the case of tax incentives, scoring is based on revenue estimates by the Joint Tax Committee, which will quantify estimated revenue losses attributable to the particular tax incentive.

Loan guarantees present more complex issues. Specifically, the Federal Credit Reform Act of 1990 ("CFA") provides that any Federal loan guarantees may be made only to the extent "new budget authority" to cover their costs is provided in advance in appropriations Acts.[30] The "cost" of a loan guarantee is the estimated net present value of payments by the government to cover defaults and delinquencies (netted against fees and recoveries).

What this limitation means in practice is that in order to receive a loan guarantee for a large-scale project, not only must there be statutory authority to issue the guarantee, there must also be sufficient new budget authority provided in an appropriations bill to cover the cost (i.e., credit risk) to the government associated with the guarantee. Credit risk is determined by CBO or by the Office of Management and Budget (OMB) based on an assessment of the financial risk to the Federal government arising from a potential default by the buyer. CBO or OMB assess this risk based on the statutory limitations on the loan guarantee (i.e., percentage of project costs guaranteed, term of the loan, requirements for vendor performance guarantees and power purchase contracts, and creditor rights the government holds in the event of default) and other factors. For example, if CBO or OMB determined that there was a 10% risk of loss on a $100 million loan guarantee, new budget authority of $10 million would be required to cover that loss.

We have not estimated the cost to the Federal government of the incentives.

ENDNOTES

[1] Information sources for this section: World Coal Institute, Gasification Technologies Council, National Coal Council, Southern Company, U.S. Department of Energy National Energy Technology Laboratory.

[2] There are three major types of gasification systems in use today: moving bed, fluidized bed, and entrained flow. Entrained flow gasifiers are similar in concept to pulverized fuel firing; fluidized bed gasifiers are similar to fluidized bed combustors; and moving bed gasifiers bear some resemblance to grate firing. Currently, the demonstrated gasifier technologies are all entrained flow and include the coal/water slurry-fed processes (GE/ChevronTexaco and E-Gas™/ConocoPhillips) and the dry-coal-fed process (Shell/Prenflo).

[3] Both of the European gasifier technologies are now owned by Shell and are commercially offered as Shell technologies.

[4] While the KBR transport gasifier—which is being developed together with Southern Company at the Power Systems Development Facility—has shown promising results with low-rank coals, there are currently no commercially demonstrated gasification technologies that cost-effectively gasify lower rank coals such as lignite and sub-bituminous.

[5] Holt, Neville, "Operating Experience and Improvement Opportunities for Coal Based IGCC Plants", *Materials at High Temperatures*, 20(1) 1-6, 2003. Note that this report also indicates that mercury removal was not required at any of the existing demonstration facilities, but that estimates are based on mercury removal from the syngas produced at the Eastman Chemical coal gasification facility operating for the past 18 years.

[6] Utility Data Institute's North American Business Directory, data through 1997. No new coal plants have been built since 1997 that would change this data.

[7] National Coal Council Report, "Opportunities to Expedite the Construction of New Coal-Based Power Plants" November 2004. Additional benefits of IGCC systems: they use less water than traditional PC plants and produce little solid waste; byproducts formed from the mineral matter in the coal can be collected and used for many purposes, such as building roads.

[8] Instead of burning the coal derived syngas to generate electricity, it can also be processed using commercially available technologies to produce a wide range of fuels, such as diesel oil, chemicals, and fertilizer or industrial gases. Some facilities have the capability to produce both electricity and other products from the syngas, depending on the plant's configuration as well as site-specific technical and market conditions. This process is referred to as "co-production" or "poly-generation." The hydrogen output can be a valuable input for refiners and chemical manufacturers.

[9] We do not address in detail other possible IGCC deployment paths, such as refueling existing natural gas combined cycle plants, that might be encouraged through incentives. These investments would face some of the same technical risks as the overall IGCC plant investment.

[10] The terms "demonstration facility" and "alternative fuel" are undefined, but both the statutory context and experience under this program indicate that full-scale commercial demonstration projects are within the ambit of this program, and it would appear that an IGCC gasifier would qualify for assistance. Loan guarantees on projects in excess of $50,000,000 must obtain specific legislative authorization before the guarantee is issued.

[11] Internal Revenue Code of 1986 ("Code" or "IRC") § 38(b) (1986). (These credits include, among others, the renewable energy production credits, solar and geothermal tax credits, alcohol fuel credits and enhanced oil recovery credits.)

[12] *See id.* § 46, 47, 48.

[13] *See id.* § 48 (a)(3).

[14] *See id.* § 38 (c)(1)(B). "Regular tax" excludes the alternative minimum tax and certain other special tax provisions. *See id.* § 26(b). The 25% rule does not apply to the first $25,000 of regular tax otherwise due

[15] *See id.* § 39. The Code, however, provides for a 1-year carryback and a 20-year carryforward that mitigate the impact of this limitation.

[16] *See id.* § 55, et. seq.

[17] *See id.* § 38 (c).

[18] *See id.* §38 (a)(3). However, carrybacks and carryovers may be available, and the Code provides exceptions for certain favored credits.

[19] The Code does provide for certain refundable credits for individuals, and for refunds under the income tax system of overpayments of excise taxes. Recent proposals for transferable renewable generation tax credits for these entities have not been successful in the Congress.

[20] Another factor in evaluating the usefulness of Federal financial incentives is the "tax normalization" policy under Federal tax law. That policy conditions the availability to regulated utilities of certain tax incentives (such as accelerated depreciation) on the utilities' regulators allowing the utility to retain the benefit of the incentive.

[21] Unregulated IGCC owners could include equipment vendors, coal producers, or industrial companies.

[22] The availabilities are not directly comparable. One existing plant experienced a commercial dispute with a contracting party. Also, both U.S. plants are often used as test beds for technology development research.

[23] The COE is calculated with EPRI's Technical Assessment Guide (TAG) 1997 methodology and spreadsheet model. The model produces the detailed cash flows associated with a single power plant investment and operation. The model represents the regulation of an investor owned utility (IOU). The cash flows depend on the cost and performance of the power plant and the details of the rate regulation. The results of COE are measured in levelized constant 2004 dollars per megawatt hour. The COE reflects such factors as interest during construction (AFUDC), the return on and of capital, and normalization of tax timing advantages. The levelized COE is calculated at the after-tax cost of capital.

The TAG model is used to calculate the value of incentives for two kinds of ownership – IOU and IPP. These types use different inputs in the EPRI spreadsheet to model the asset owner. Examples of input data that changes are debt and equity fractions, cost of debt and equity, and income tax rates. While the TAG model carefully represents an IOU, it also calculates the COE for IPP owners. IOU regulation varies across the country. However experience shows that these differences cause minor changes in COE. IPP owners may use other ways of calculating COE, but the impact of incentives on their COE is approximately represented by TAG. Finally, rate making at Public Power utilities does not mirror the TAG results. A separate spreadsheet has been constructed to calculate COE for these organizations. These methods define the Public Power COE with acceptable accuracy.

COE is a good measure of technology attractiveness. However, it will not determine project owner behavior in every instance. This analysis compares the IGCC plant with a PC plant. Some organizations may find that strategic or profitability issues indicate that they should invest in nothing or in alternatives such as nuclear, gas fueled generation renewables, and/or DSM. Of course, a company that believes its financial future depends on being able to develop and operate IGCC plants may invest in their first IGCC plant with a COE disadvantage. The COE method does not monetize any differences between IGCC and PC by using prices for SO_X, NO_X, mercury or CO_2 emission allowances. Such monetization would close the COE gap somewhat (by about $0.50 today for SO_X and NO_X). Looking forward, increasing environmental costs could decrease the gap by around $1.00 by 2010 given current forward market estimates, but would also make all coal plants relatively less attractive compared to other lower emitting generating technologies. Finally, while the COE method is a good way of understanding how various incentives can bridge the COE difference, the COE results cannot be compared between different ownership types because of the detailed assumptions in the methods.

[24] Fees can vary greatly. Several internet sites provide example calculators for estimating these fees (note that the actual fee can vary from the calculator result). An ExIm Bank loan to the government of Canada drawn down over 36 months that is paid back over 30 years has a fee of about 4%. Reducing the draw down time or the payback period reduces the fee. A Transportation Infrastructure Financing loan for a BBB+/Baa1 debtor has a fee of 1.6% for a 4 year draw down and 25-year payback loan. A B/B2 borrower has a fee of 16.17% for the same loan. Berg and Paterson (David.Berg@hq.doe.gov) provide a deeper level of explanation as well as several examples in a January 29, 2004 presentation.

[25] Availability refers to overall plant availability, rather than just the availability of syngas. In all calculations, we assumes that the IGCC dispatches when available. A backup fuel supply for the combined cycle gas turbines can lessen availability problems, but due to heat rate inefficiencies and fuel cost, is unlikely to be used (dispatched) often.

[26] U.S. Const. art. I § 9, cl. 7.

[27] Pub. L. No. 93-344 (codified as amended in scattered sections of the U.S. Code).

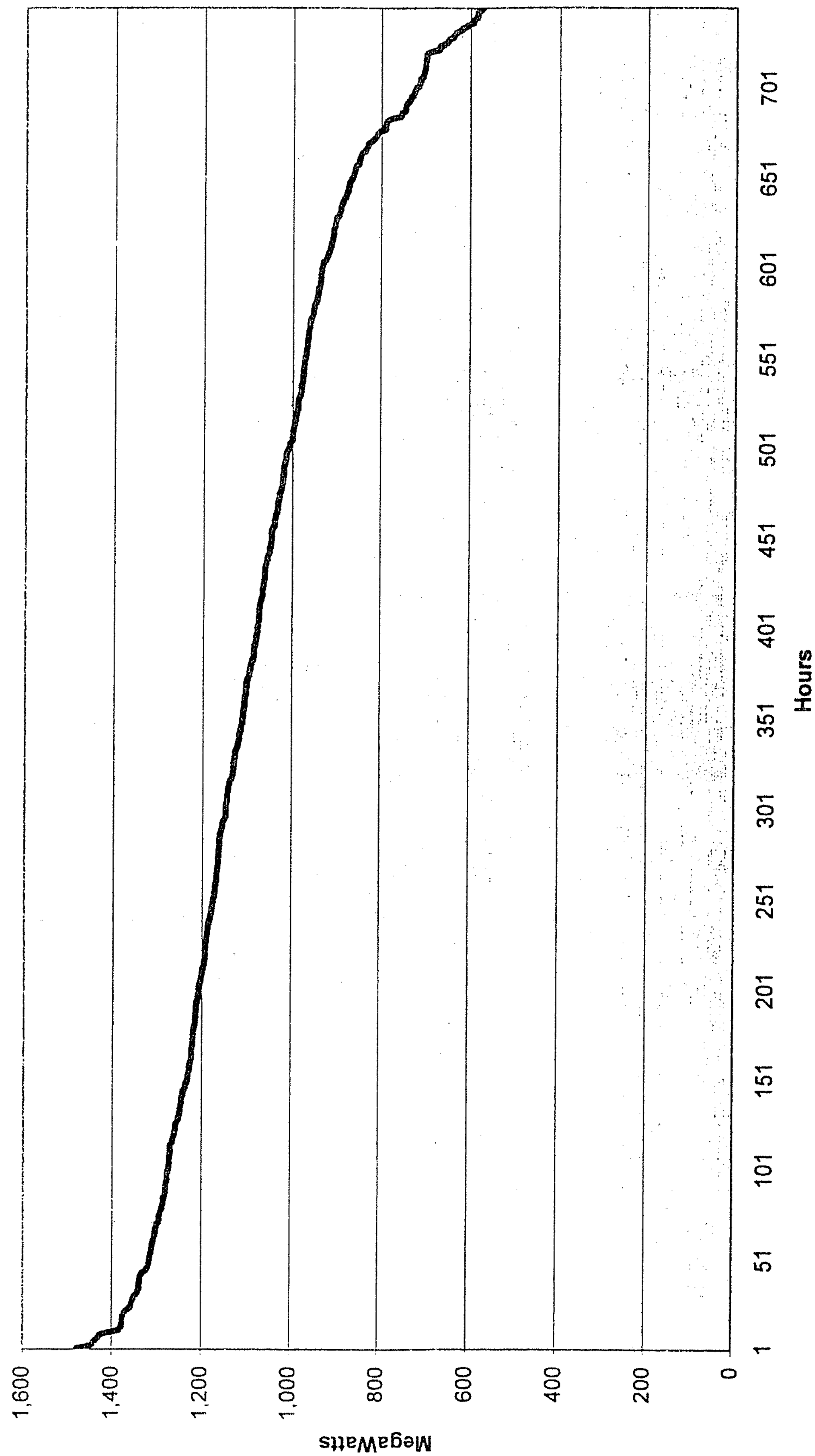
[28] In addition, the Appropriations Committees are required to subdivide their 302 (a) allocations among their subcommittees. These are called 302 (a) allocations, after the section of the Congressional Budget Act that requires them to be made.

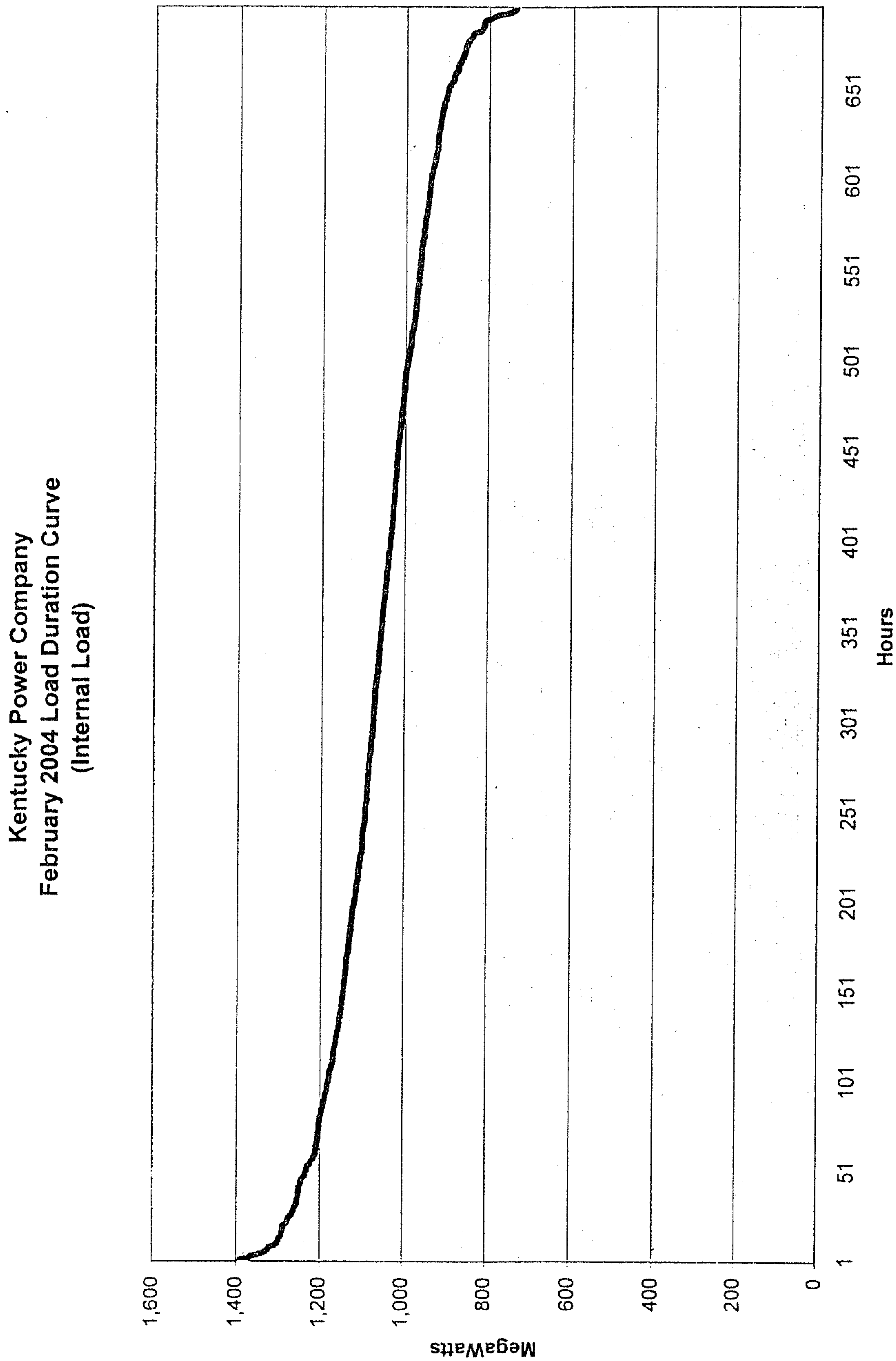
[29] 31 U.S.C. §§ 1341, 1342, 1349-1351, 1511-1519.

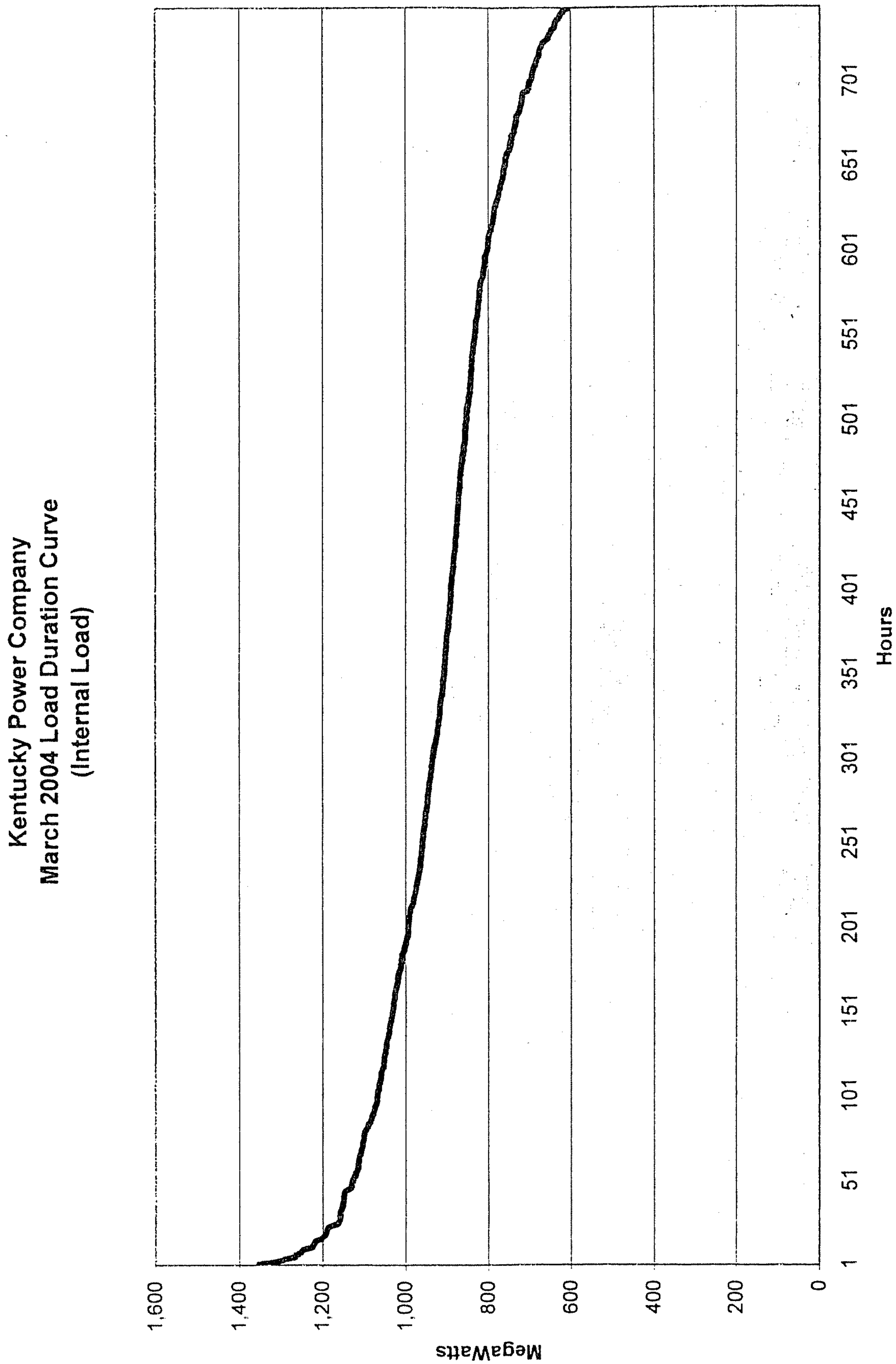
[30] Budget authority is a provision of law that makes funds available for obligation and expenditure, or contract authority to incur obligations.

APPENDIX B

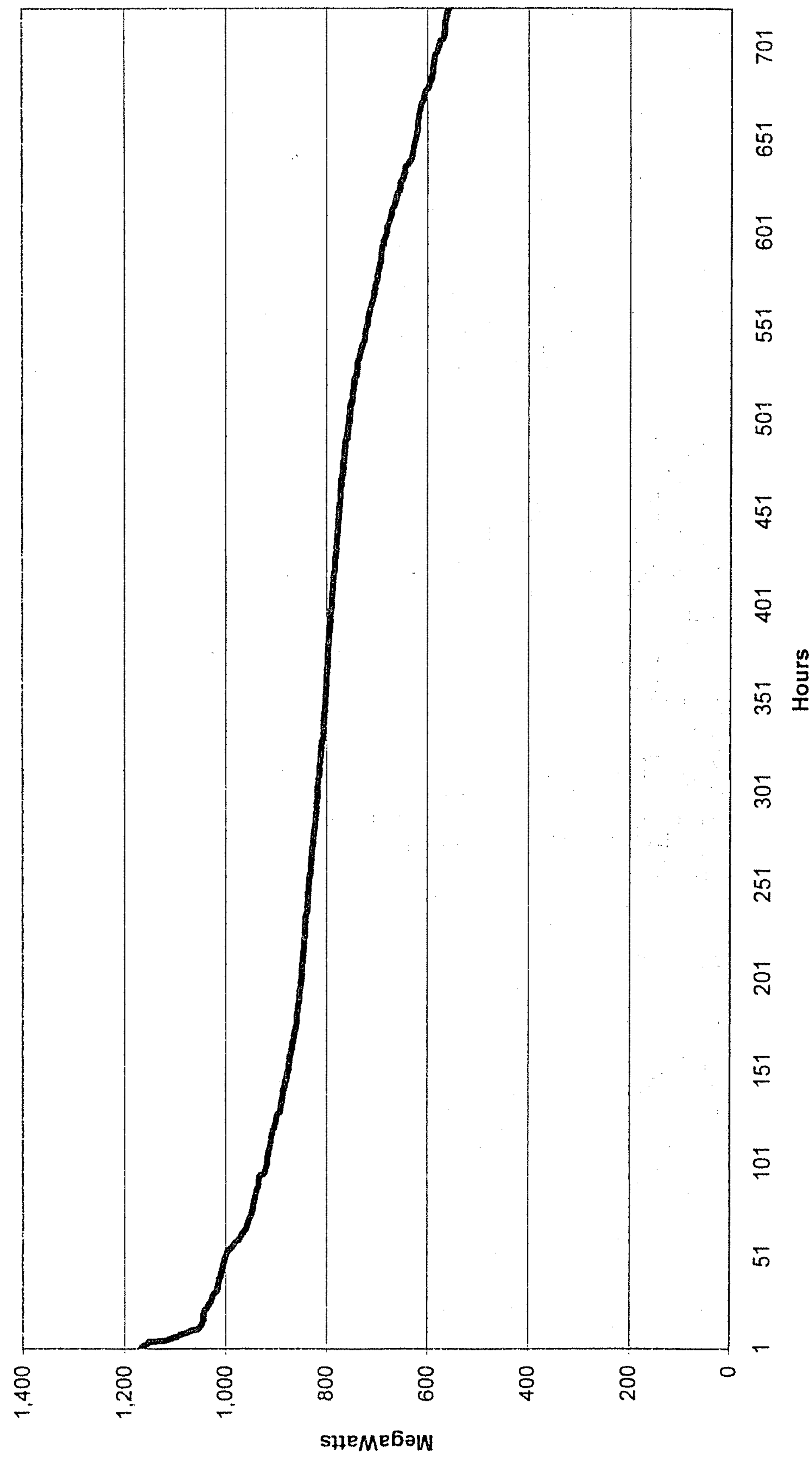
Kentucky Power Company
January 2004 Load Duration Curve
(Internal Load)

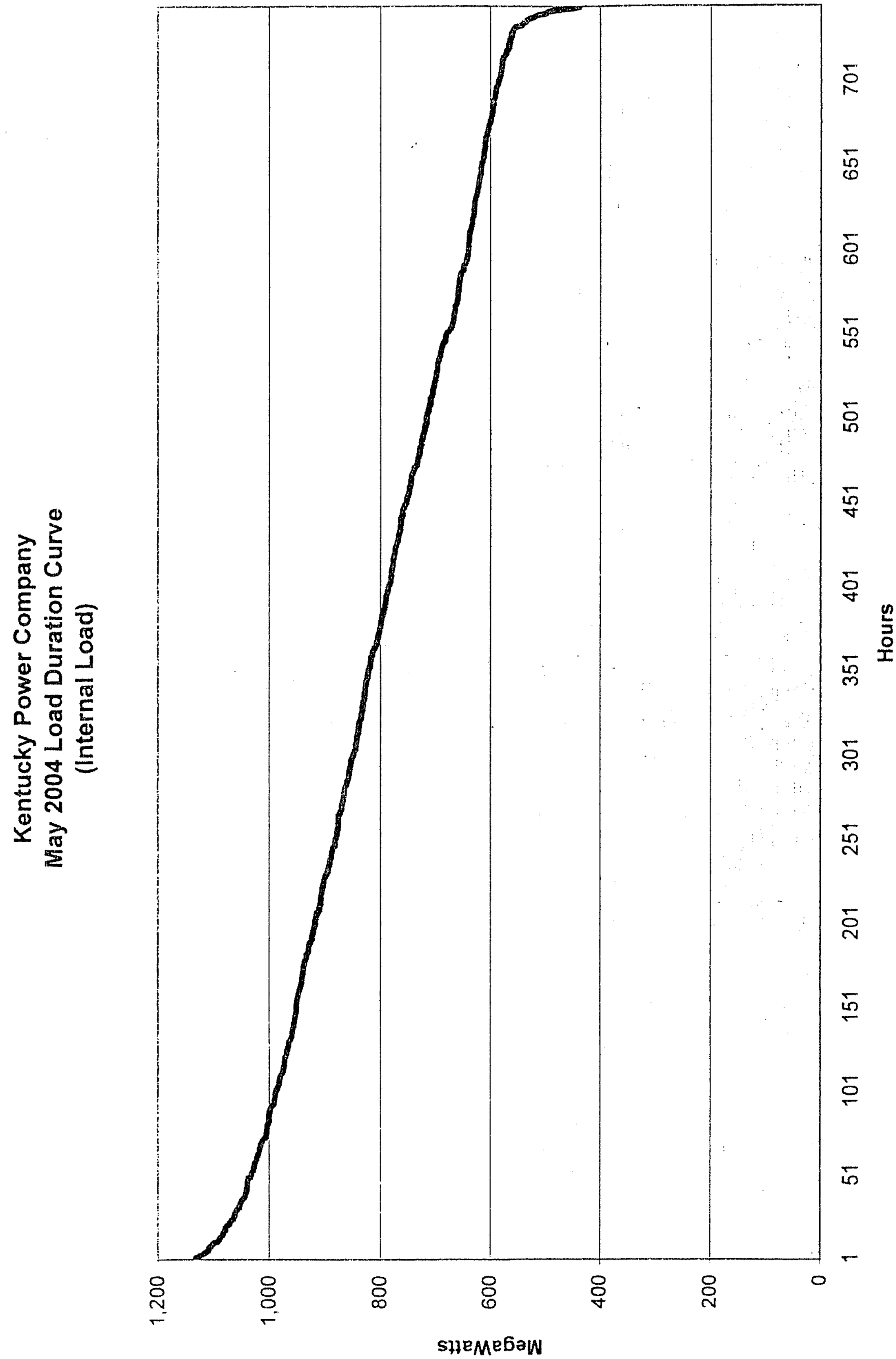



Kentucky Power Company
February 2004 Load Duration Curve
(Internal Load)
MegaWatts
1,600
1,400
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651

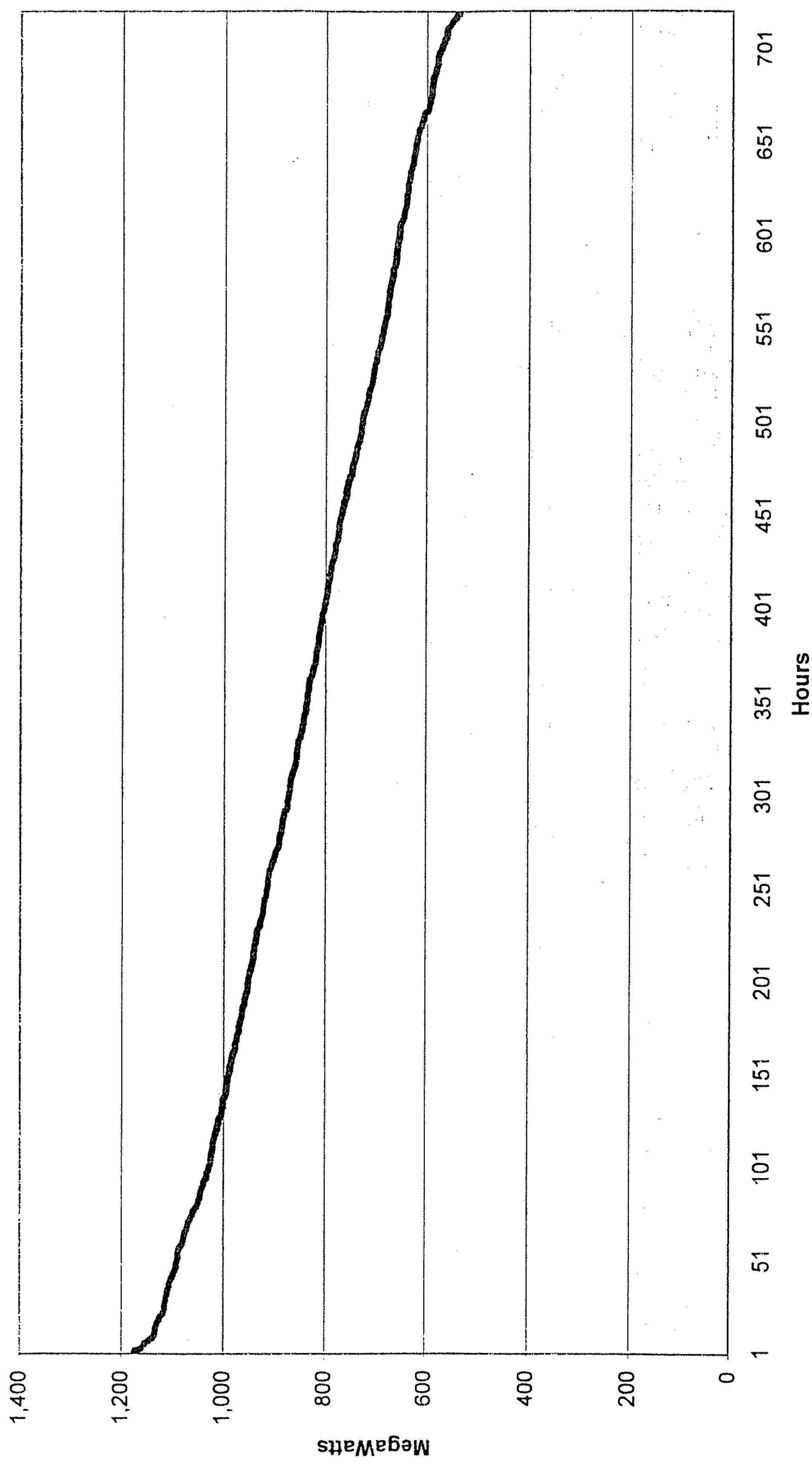

Kentucky Power Company
March 2004 Load Duration Curve
(Internal Load)
MegaWatts
1,600
1,400
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

Kentucky Power Company
April 2004 Load Duration Curve
(Internal Load)

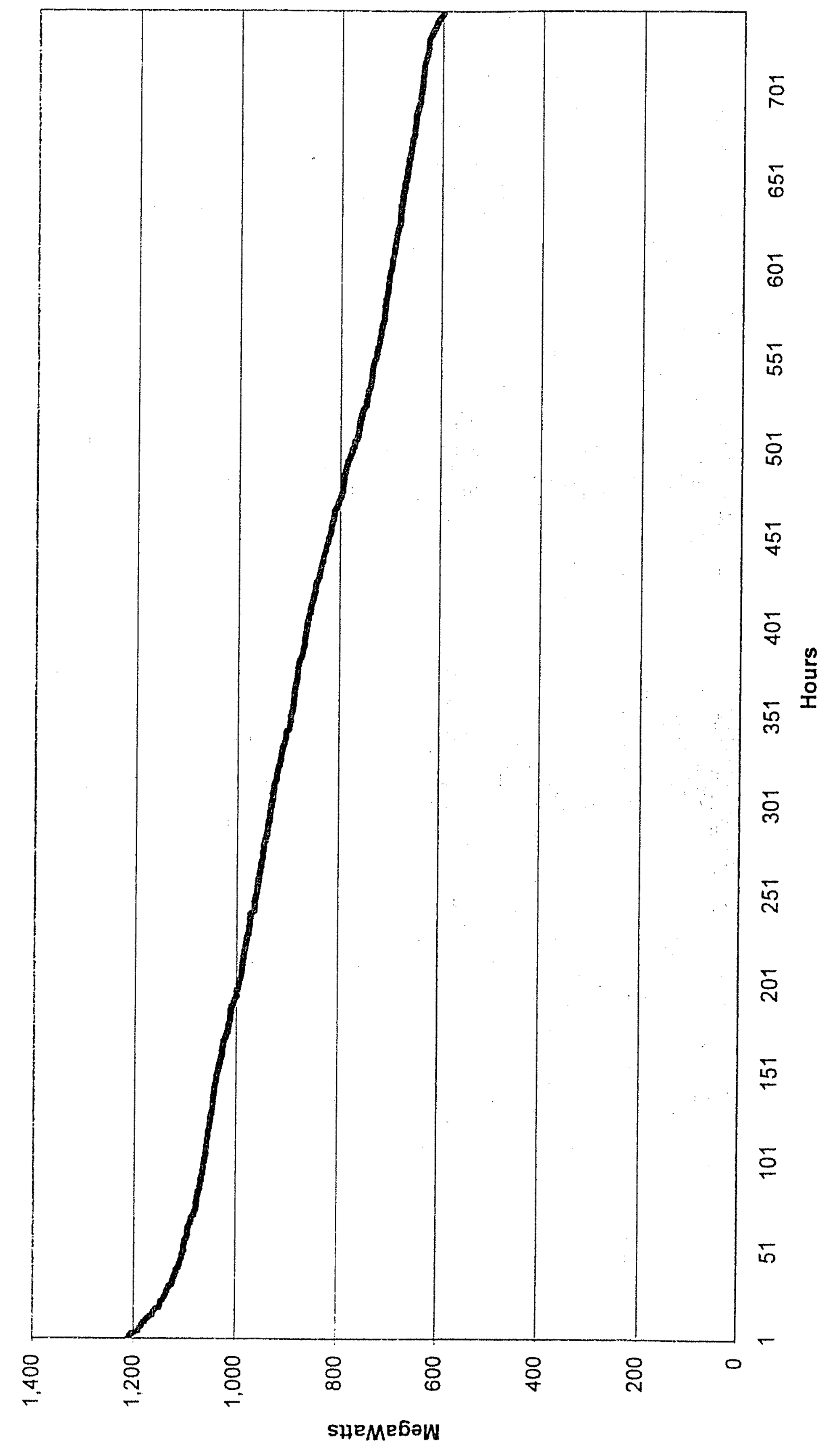


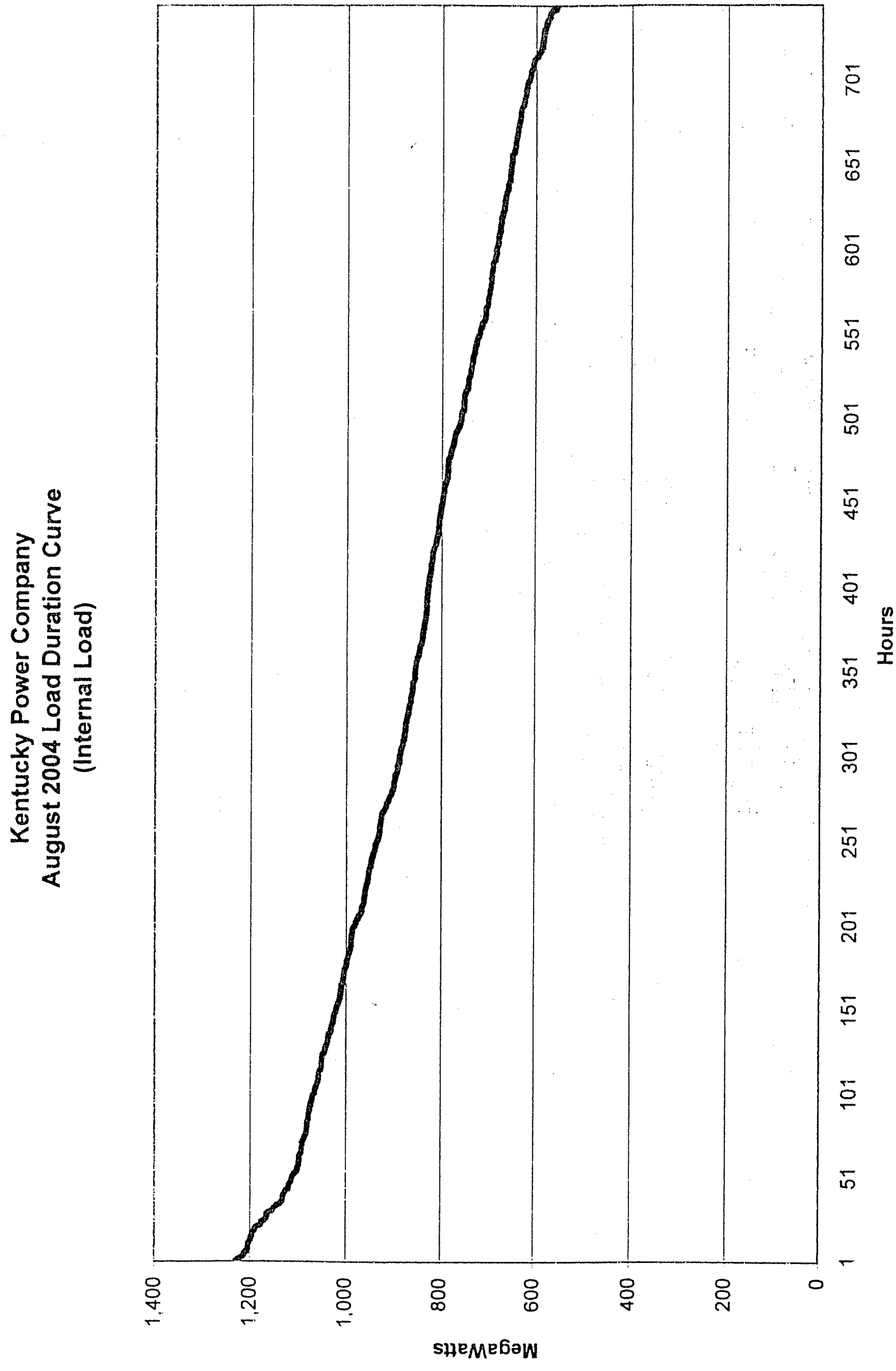

Kentucky Power Company
May 2004 Load Duration Curve
(Internal Load)
MegaWatts
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

Kentucky Power Company
June 2004 Load Duration Curve
(Internal Load)

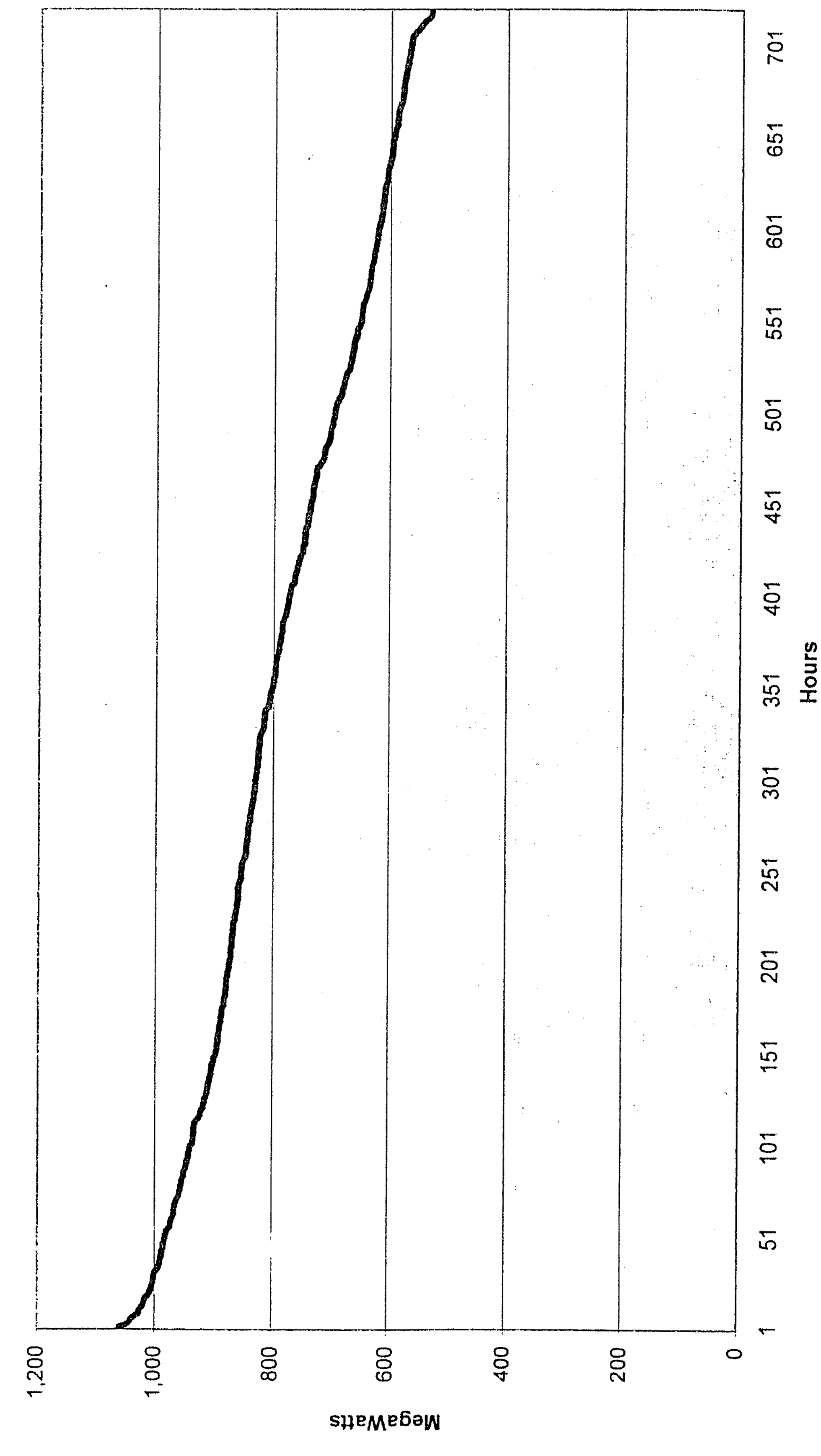


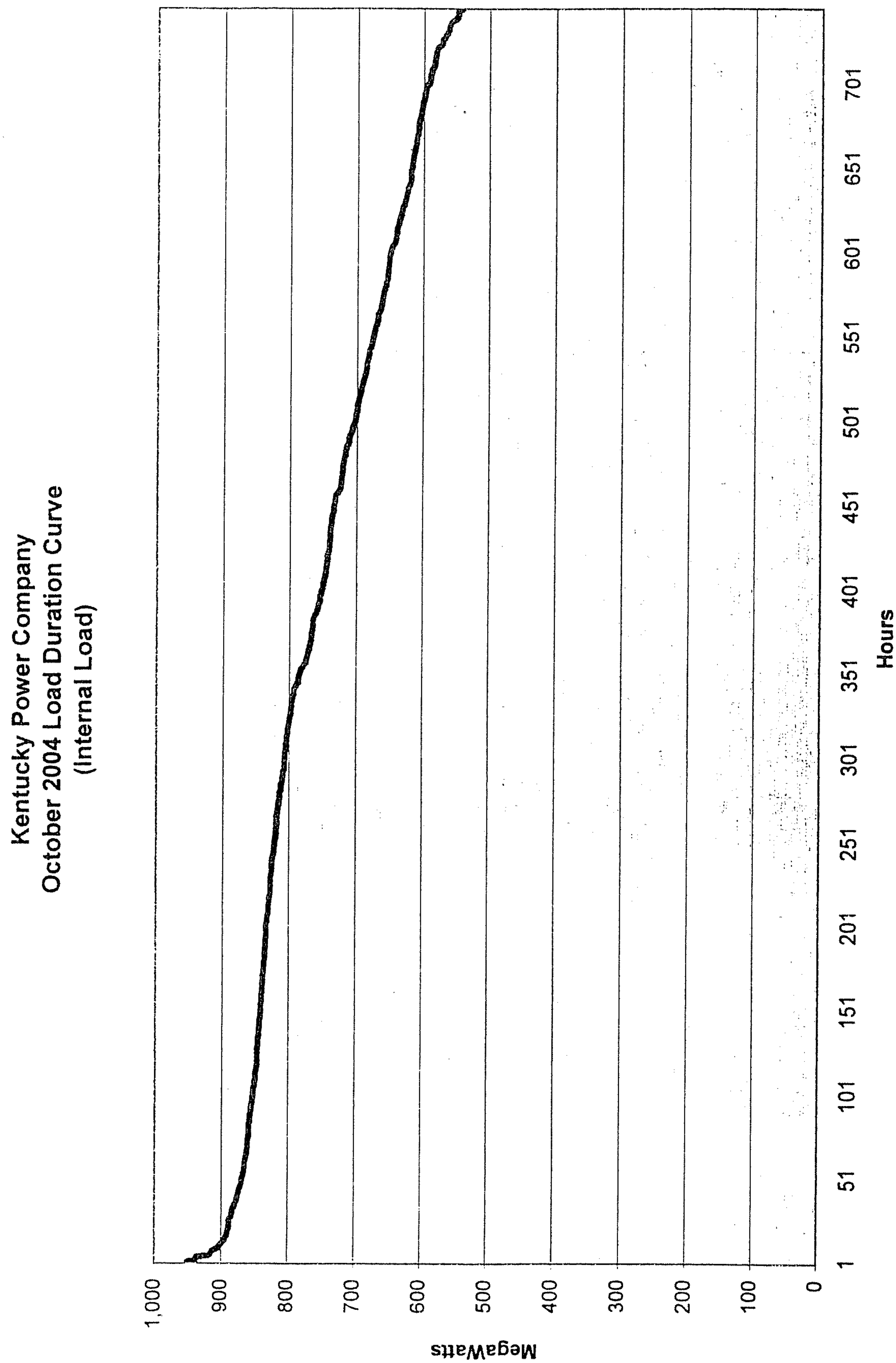
Kentucky Power Company
July 2004 Load Duration Curve
(Internal Load)



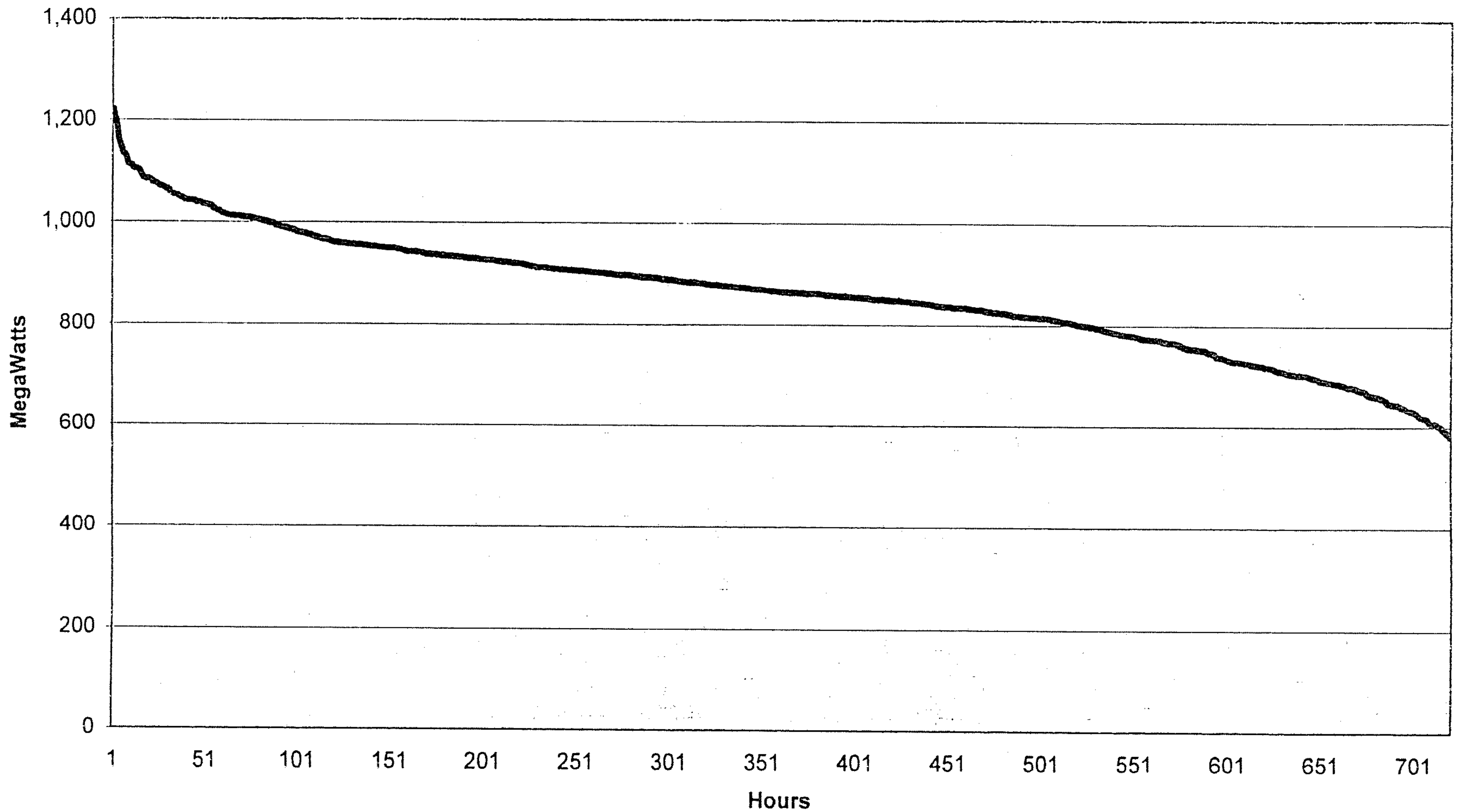

Kentucky Power Company
August 2004 Load Duration Curve
(Internal Load)
MegaWatts
1,400
1,200
1,000
800
600
400
200
0
Hours
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701

Kentucky Power Company
September 2004 Load Duration Curve
(Internal Load)

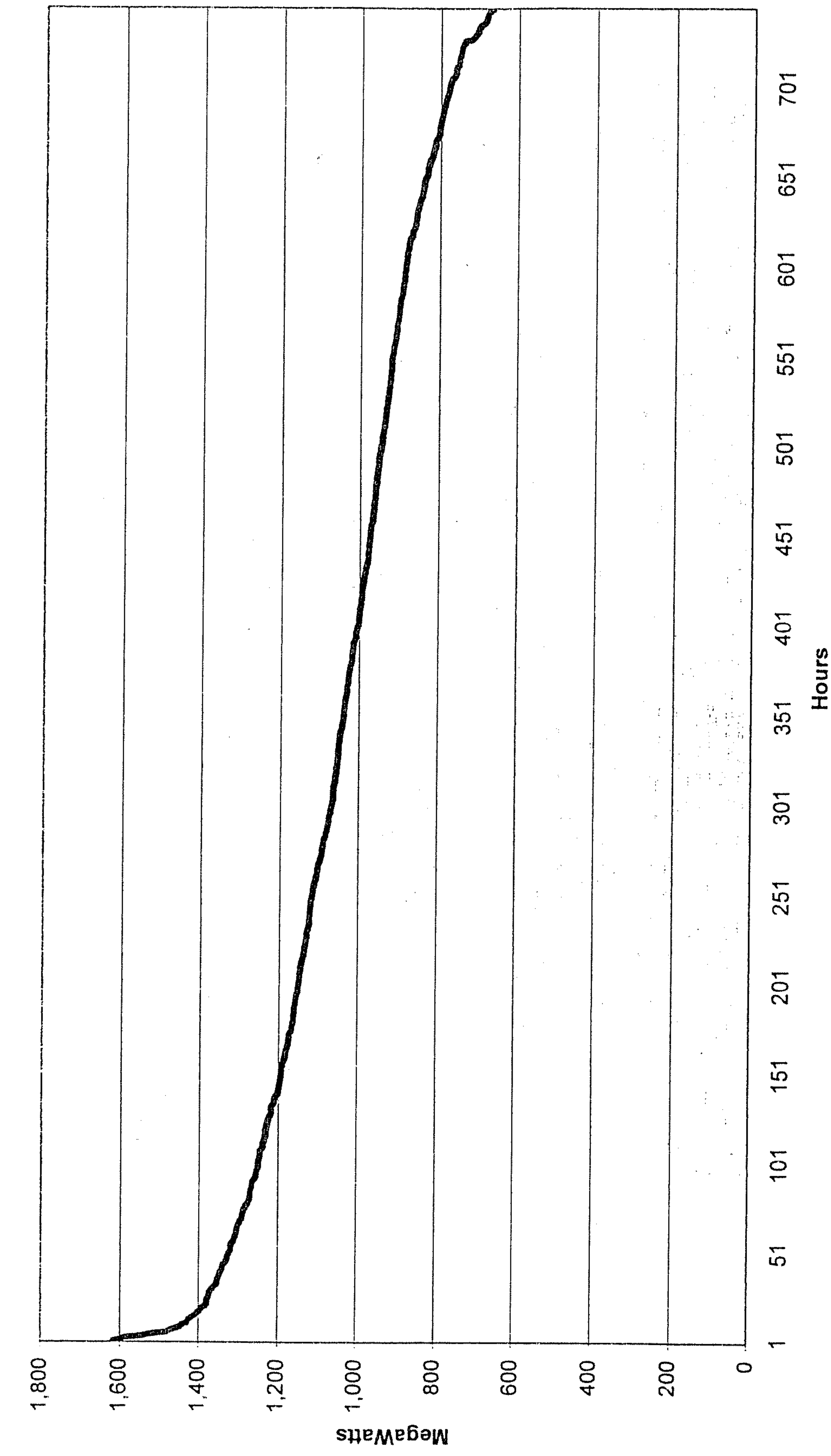



Kentucky Power Company
October 2004 Load Duration Curve
(Internal Load)
MegaWatts
1,000
900
800
700
600
500
400
300
200
100
0
1
51
101
151
201
251
301
351
401
451
501
551
601
651
701
Hours

Kentucky Power Company
November 2004 Load Duration Curve
(Internal Load)



Kentucky Power Company
December 2004 Load Duration Curve
(Internal Load)



APPENDIX C

ENROLLED

COMMITTEE SUBSTITUTE

FOR

Senate Bill No. 455

(

Senators Helmick, Hunter, Bowman, Facemyer,

Sharpe, Sprouse, Kessler, McCabe, Edgell,

Plymale, Love, Prezioso, Dempsey, Barnes and Jenkins, *original sponsors*)

[Passed April 9, 2005; in effect from passage.]

AN ACT to amend the Code of West Virginia, 1931, as amended, by adding thereto a new section, designated §24-2-4e; and to amend and reenact §46-9-109 of said code, all relating generally to the financing of environmental control activities by certain qualified electric utilities through the issuance of environmental control bonds.

Be it enacted by the Legislature of West Virginia:
That the Code of West Virginia, 1931, as amended, be amended by adding thereto a new section, designated §24-2-4e; and that §46-9-109 of said code be amended and reenacted, all to read as follows:

CHAPTER 24. PUBLIC SERVICE COMMISSION.

ARTICLE 2. POWERS AND DUTIES OF PUBLIC SERVICE COMMISSION.

§24-2-4e. Environmental control bonds.

(a) *Legislative findings*. -- The Legislature hereby finds and declares: (i) That electric utilities in the state face the need to install and construct emission control equipment at existing generating facilities in the state in order to meet the requirements of existing and anticipated environmental laws and regulations and otherwise to reduce emissions from those electric generating facilities; (ii) that the capital costs associated with the installation and construction of emission control equipment are considerable; (iii) that the financial condition of some electric utilities may make the use of traditional utility financing mechanisms to finance the construction and installation of emission control equipment difficult or impossible and that this situation may cause such utilities to defer the installation of emission control equipment, to incur higher financing costs, to minimize or eliminate their use of high-sulfur coal mined in the State or to use other financing alternatives that are less favorable to the state and its citizens; (iv) that the construction and installation of emission control equipment by utilities will create public health and economic benefits to the state and its citizens, including, without limitation, emissions reductions, economic development, job growth and retention and the increased use of high-sulfur coal mined in the State; (v) that customers of electric utilities in the state have an interest in the construction and installation of emission control equipment at electric-generating facilities in the state at a lower cost than would be afforded by traditional utility financing mechanisms; (vi) that alternative financing mechanisms exist which can result in lower costs to customers and the use of these mechanisms can ensure that only those costs associated with the construction and installation of emission control equipment at electric-generating facilities located in the state that generate electric energy for their ultimate use will be included in customer rates; and (vii) that in order to use such alternative financing mechanisms, the Commission must be empowered to adopt a financing order that advances these goals. The Legislature, therefore, finds that it is in the interest of the state and its citizens to encourage and facilitate the use of alternative financing mechanisms that will enable certain utilities to finance the construction and installation of emission control equipment at electric-generating facilities in the state under certain conditions and to empower the Commission to review and approve alternative financing mechanisms as being consistent with the public interest, as set forth in this section.

(b) *Definitions.* --

As used in this section:

(1) "Adjustment mechanism" means a formula-based mechanism for making any adjustments to the amount of the environmental control charges that are necessary to correct for any over-collection or under-collection of the environmental control charges or otherwise to ensure the timely and complete payment and recovery of environmental control costs and financing costs. The adjustment mechanism is not to be used as a means to authorize the issuance of environmental control bonds in a principal amount greater, or the payment or recovery of environmental control costs in an amount greater, than that which was authorized in the financing order which established the adjustment mechanism.

(2) "Ancillary agreement" means any bond insurance policy, letter of credit, reserve account, surety bond, swap arrangement, hedging arrangement, liquidity or credit support arrangement or other similar agreement or arrangement entered into in connection with the issuance of environmental control bonds that is designed to promote the credit quality and marketability of the bonds or to mitigate the risk of an increase in interest rates.

(3) "Assignee" means any person or legal entity to which an interest in environmental control property is sold, assigned, transferred or conveyed (other than as security) and any successor to or subsequent assignee of such a person or legal entity.

(4) "Bondholder" means any holder or owner of an environmental control bond.

(5) "Environmental control activity" means any of the following:

(A) The construction, installation and placing in operation of environmental control equipment at a qualifying generating facility.

(B) The shutdown or retirement of any existing plant, facility, unit or other property at a qualifying generating facility to reduce, control or eliminate environmental emissions. (6) "Environmental control bonds" means bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership or other evidences of indebtedness or ownership that are issued by a qualifying utility or an assignee, the proceeds of which are used directly or indirectly to recover, finance, or refinance environmental control costs and financing costs, and that are secured by or payable from environmental control revenues.

(7) "Environmental control charge" means a nonbypassable charge paid by a customer of a qualifying utility for the recovery of environmental control costs and financing costs.

(8) "Environmental control cost" means any cost, including capitalized cost relating to regulatory assets and capitalized cost associated with design and engineering work, incurred or expected to be incurred by a qualifying utility in undertaking an environmental control activity and, with respect to an environmental control activity, includes the unrecovered value of property that is retired, together

with any demolition or similar cost that exceeds the salvage value of the property. "Environmental control cost" includes preliminary expenses and investments associated with environmental control activity that are incurred prior to the issuance of a financing order and that are to be reimbursed from the proceeds of environmental control bonds. "Environmental control cost" does not include any monetary penalty, fine or forfeiture assessed against a qualifying utility by a government agency or court under a federal or state environmental statute, rule or regulation.
(9) "Environmental control equipment" means any device, equipment, structure, process, facility or technology that is designed for the primary purpose of preventing, reducing or remediating environmental emissions and that has been or is to be constructed or installed at a qualifying generating facility.
(10) "Environmental control property" means all of the following:
(A) The rights and interests of a qualifying utility or an assignee under a financing order, including the right to impose, charge, collect and receive environmental control charges in the amount necessary to provide for the full payment and recovery of all environmental control costs and financing costs determined to be recoverable in the financing order and to obtain adjustments to the charges as provided in this section and any interest in the rights and interests.
(B) All revenues, receipts, collections, rights to payment, payments, moneys, claims or other proceeds arising from the rights and interests specified in paragraph (A) of this subdivision.
(11) "Environmental control revenues" means all revenues, receipts, collections, payments, moneys, claims or other proceeds arising from environmental control property.
(12) "Environmental emissions" means the discharge or release of emissions from electric generating facilities into the air, land or waters of the state.
(13) "Equity ratio" means, as of any given time of determination, the common equity of a qualifying utility as calculated pursuant to the uniform system of accounts required to be used in the filings of the qualifying utility with the federal Energy Regulatory Commission. "Equity ratio" shall be calculated excluding the effect of the issuance of environmental control bonds or the write down of discontinued operations.
(14) "Financing cost" means the costs to issue, service, repay, or refinance environmental control bonds, whether incurred or paid upon issuance of the bonds or over the life of the bonds, and approved for recovery by the Commission in a financing order. "Financing cost" may include any of the following:
(A) Principal, interest and redemption premiums that are payable on environmental control bonds.
(B) Any payment required under an ancillary agreement and any amount required to fund or replenish a reserve account or other account established under any indenture, ancillary agreement or other financing document relating to the environmental control bonds.
(C) The cost of retiring or refunding any existing debt and equity securities of a qualifying utility in connection with the issuance of environmental control bonds, but only to the extent the securities were issued for the purpose of financing environmental control costs.
(D) Any costs incurred by or on behalf of or allocated to a qualifying utility to obtain modifications of or amendments to any indenture, financing agreement, security agreement or similar agreement or instrument relating to any existing secured or unsecured obligation of a qualifying utility or an affiliate of a qualifying utility, or any costs incurred by or allocated to a qualifying utility to obtain any consent, release, waiver or approval from any holder of such an obligation, that are necessary to be incurred to permit a qualifying utility to issue or cause the issuance of environmental control bonds.
(E) Any taxes, franchise fees or license fees imposed on environmental control revenues.
(F) Any cost related to issuing and servicing environmental control bonds or the application for a financing order, including, without limitation, servicing fees and expenses, trustee fees and expenses, legal fees and expenses, administrative fees, placement fees, capitalized interest, rating agency fees and any other related cost that is approved for recovery in the financing order.

(15) "Financing order" means an order of the Commission pursuant to subsection (d) of this section that grants, in whole or in part, an application filed pursuant to subsection (c) of this section and that authorizes the construction and installation of environmental control equipment, the issuance of environmental control bonds in one or more series, the imposition, charging and collection of environmental control charges, and the creation of environmental control property. A financing order may set forth conditions or contingencies on the effectiveness of the relief authorized therein and may grant relief that is different from that which was requested in the application.
(16) "Financing parties" means:
(A) Any trustee, collateral agent or other person acting for the benefit of any bondholder.
(B) Any party to an ancillary agreement the rights and obligations of which relate to or depend upon the existence of environmental control property, the enforcement and priority of a security interest in environmental control property, the timely collection and payment of environmental control revenues or a combination of these factors.
(17) "Financing statement" means a financing statement as defined in subdivision (39), subsection (a), section one hundred two, article nine, chapter forty-six of this code.
(18) "Investment grade" means, with respect to the unsecured debt obligations of a qualifying utility at any given time of determination, a rating that is within the top four investment rating categories as published by at least one nationally recognized statistical rating organization as recognized by the United States Securities and Exchange Commission.
(19) "Nonbypassable" means that the payment of an environmental control charge may not be avoided by any electric service customer located within a utility service area, and must be paid by any such customer that receives electric delivery service from the qualifying utility for as long as the environmental control bonds are outstanding.
(20) "Nonutility affiliate" means, with respect to any qualifying utility, a person that: (i) Is an affiliate of the qualifying utility as defined in 15 U. S. C. §79b(a)(11); and (ii) is not a public utility that provides retail utility service to customers in the state within the meaning of section two, article one of this chapter.
(21) "Parent" means, with respect to any qualifying utility, any registered holding company or other person that holds a majority ownership or membership interest in the qualifying utility.
(22) "Qualifying generating facility" means any electric generating facility that: (i) Has generated electric energy for ultimate sale to customers in the state before the effective date of this section; and (ii) is owned by a qualifying utility or, on the expected date of issuance of the environmental control bonds authorized in a financing order, will be owned by a qualifying utility.
(23) "Qualifying utility" means:
(A) Any public utility that is: (i) Engaged in the delivery of electric energy to customers in this state; and (ii) at any time between the date which is two years immediately preceding the effective date of this section and the date on which an application for a financing order is made, has or had a credit rating on its unsecured debt obligations that is below investment grade.
(B) For so long as environmental control bonds issued pursuant to a financing order are outstanding and the related environmental control costs and financing costs have not been paid in full, the public utility to which the financing order was issued and its successors.
(24) "Registered holding company" means, with respect to a qualifying utility, a person that is: (i) A registered holding company as defined in 15 U. S. C. §79b(a)(12); and (ii) an affiliate of the qualifying utility as defined in 15 U. S. C. §79b(a)(11).
(25) "Regulatory sanctions" means, under the circumstances presented, any regulatory or ratemaking sanction or penalty that the Commission is authorized to impose pursuant to this chapter or any proceeding for the enforcement of any provision of this chapter or any order of the Commission that the Commission is authorized to pursue or conduct pursuant to this chapter, including without limitation: (i) The initiation of any proceeding in which the qualifying utility is required to show cause why it should not be required to comply with the terms and conditions of a financing order or

the requirements of this section; (ii) the imposition of civil penalties pursuant to section three, article four of this chapter and the imposition of criminal penalties pursuant to section four of said article, in either case with reference to the provisions of section eight of said article; and (iii) a proceeding by mandamus or injunction as provided in section two of this article.

(26) "Successor" means, with respect to any legal entity, another legal entity that succeeds by operation of law to the rights and obligations of the first legal entity pursuant to any bankruptcy, reorganization, restructuring or other insolvency proceeding, any merger, acquisition, or consolidation, or any sale or transfer of assets, whether any of these occur as a result of a restructuring of the electric power industry or otherwise.

(27) "Utility service area" means: (i) The geographic area of the state in which a qualifying utility provides electric delivery service to customers at the time of issuance of a financing order; and (ii) for as long as environmental control bonds issued pursuant to a financing order are outstanding, any additions to or enlargements of said geographic area, whether or not approved by the Commission in a formal proceeding.

(c) *Application for financing order.* --

(1) A qualifying utility, or two or more affiliated qualifying utilities, may apply to the Commission for a financing order under this section.

(2) An application for a financing order under this section shall be filed only as provided in this subdivision.

(A) An application for a financing order under this section shall be filed as part of the application of the qualifying utility or qualifying utilities under section eleven of this article for a certificate of public convenience and necessity to engage in environmental control activities.

(B) If a qualifying utility or qualifying utilities have an application for a certificate of public convenience and necessity to engage in environmental control activities pending before the Commission on the effective date of this section, the qualifying utility or qualifying utilities may file a separate application for a financing order and the Commission shall join or consolidate the application for a financing order with the pending application for a certificate of public convenience and necessity. Notwithstanding any provision of section eleven of this article to the contrary or the total project cost of the proposed environmental control activities, the Commission shall render its final decision on any joined or consolidated proceeding for a certificate of public convenience and necessity and a financing order as described in this paragraph within two hundred seventy days of the filing of the application for the financing order and within ninety days after final submission of the joined or consolidated application for decision following a hearing.

(3) In addition to any other information required by the Commission, an application for a financing order shall include the following information:

(A) Evidence that the applicant is a qualifying utility;

(B) A description of the environmental control activities that the qualifying utility proposes to undertake, including a detailed description of the environmental control equipment to be constructed or installed at one or more qualifying generation facilities;

(C) An explanation why the environmental control activities described in the application are necessary in the context of the qualifying utility's operations, current and anticipated environmental regulations, the prospect of enforcement proceedings or litigation against the qualifying utility if the environmental control activities are not undertaken and the utility's long-range environmental compliance plans;

(D) A description of any alternatives to the environmental control activities described in the application that the qualifying utility considered and an explanation of why each alternative either is not feasible or was not selected;

(E) An estimate of the environmental control costs associated with the environmental control activities described in the application, including the estimated cost of the environmental control equipment proposed to be installed;

(F) An estimated schedule for the construction or installation of the environmental control equipment;
(G) An estimate of the date on which the environmental control bonds are expected to be issued and the expected term over which the financing costs associated with the issuance are expected to be recovered, or if the bonds are expected to be issued in more than one series, the estimated issuance date and expected term for each bond issuance;
(H) The portion of the environmental control costs the qualifying utility proposes to finance through the issuance of one or more series of environmental control bonds;
(I) An estimate of the financing costs associated with each series of environmental control bonds proposed to be issued;
(J) An estimate of the amount of the environmental control charges necessary to recover the environmental control costs and financing costs estimated in the application and the proposed calculation thereof, which estimate and calculation should take into account the estimated date of issuance and estimated principal amount of each series of environmental control bonds proposed to be issued;
(K) A proposed methodology for allocating financing costs among customer classes;
(L) A description of the proposed adjustment mechanism; and
(M) A description of the benefits to the customers of the qualifying utility and the state that are expected to result from the financing of the environmental control costs with environmental control bonds as opposed to the use of traditional utility financing mechanisms.
(4) An application for a financing order may restate or incorporate by reference any information required pursuant to subdivision (3) of this subsection that the qualifying utility previously filed with the Commission in connection with an application for a certificate of public convenience and necessity under section eleven of this article as described in paragraph (B), subdivision (2) of this subsection.
(d) *Issuance of financing order.* --
(1) Notice of an application for a financing order shall be given as a Class I legal advertisement in compliance with the provisions of article three, chapter fifty-nine of this code, with the publication area being each county in which the environmental control activities are to be undertaken and each county in the state in which the qualifying utility provides service to customers. If no substantial protest is received within thirty days after the publication of notice, the Commission may waive formal hearing on the application.
(2) The Commission shall issue a financing order, or an order rejecting the application for a financing order, as part of its final order on the application of the qualifying utility or qualifying utilities for a certificate of public convenience and necessity to engage in environmental control activities as described in subdivision (2), subsection (c) of this section.
(3) The Commission shall issue a financing order if the Commission finds all of the following:
(A) That the applicant is a qualifying utility;
(B) That the environmental control activities, including the environmental control equipment to be constructed or installed at one or more qualifying generation facilities, are necessary and prudent under the circumstances and are preferable to any alternatives available to the qualifying utility;
(C) That the cost of the environmental control activities, including the environmental control equipment to be constructed or installed at one or more qualifying generation facilities, is reasonable;
(D) That the proposed issuance of environmental control bonds will result in overall costs to customers of the qualifying utility that: (1) Are lower than would result from the use of traditional utility financing mechanisms; and (2) are just and reasonable;
(E) That the financing of the environmental control costs with environmental control bonds will result in benefits to the customers of the qualifying utility and the state; and
(F) That the proposed issuance of environmental control bonds, together with the imposition and

collection of the environmental control charges on customers of the qualifying utility, are just and reasonable and are otherwise consistent with the public interest and constitute a prudent, reasonable and appropriate mechanism for the financing of the environmental control activities described in the application.
(4) The Commission shall include the following findings and requirements in a financing order:
(A) A determination of the maximum amount of environmental control costs that may be financed from proceeds of environmental control bonds authorized to be issued in the financing order;
(B) A description of the financing costs that may be recovered through environmental control charges and the period over which the costs may be recovered, subject to the application of the adjustment mechanism as provided in subsection (e) of this section. As part of this description, the Commission may include qualitative or quantitative limitations on the financing costs authorized in the financing order;
(C) A description of the adjustment mechanism and a finding that it is just and reasonable; and
(D) A description of the environmental control property that is created and that may be used to pay, and secure the payment of, the environmental control bonds and financing costs authorized to be issued in the financing order.
(5) A financing order may provide that the creation of environmental control property shall be simultaneous with the sale of the environmental control property to an assignee as provided in the application and the pledge of the environmental control property to secure environmental control bonds.
(6) A financing order may authorize the qualifying utility to conduct environmental control activities, including the construction or installation of environmental control equipment, on an estimated schedule approved in the financing order and through the issuance of more than one series of environmental control bonds. In this case, the qualifying utility will not subsequently be required to secure a separate financing order for each issuance of environmental control bonds or for each scheduled phase of the construction or installation of environmental control equipment approved in the financing order.
(7) The Commission may require, as a condition to the effectiveness of the financing order but in every circumstance subject to the limitations set forth in subdivision (1), subsection (f) of this section, that the qualifying utility give appropriate assurances to the Commission that the qualifying utility and its parent will abide by the following conditions during any period in which any environmental control bonds issued pursuant to the financing order are outstanding, in addition to any other obligation either may have under this code or federal law:
(A) Without first obtaining the prior consent and approval of the Commission, the qualifying utility will not:
(1) Lend money, directly or indirectly, to a registered holding company or a nonutility affiliate; or
(2) Guarantee the obligations of a registered holding company or a nonutility affiliate.
(B) If: (i) For a period of twelve consecutive months immediately preceding the date of determination, the qualifying utility has had an equity ratio of below thirty percent and neither the qualifying utility nor its parent has had a credit rating on its unsecured debt obligations that is investment grade; and (ii) the Commission determines that the present ability of the qualifying utility to meet its public service obligations would be impaired by the payment of dividends, the Commission may order the qualifying utility to limit or cease the payment of dividends for a period not exceeding one hundred eighty days from the date of determination, which order may be extended for one or more additional periods not to exceed one hundred eighty days each if the Commission determines that the conditions set forth in this paragraph continue to exist as of the date of each such determination.
(C) Neither the parent nor a nonutility affiliate will direct or require the qualifying utility to file a voluntary petition in bankruptcy: *Provided*, That nothing in this paragraph shall preclude the qualifying utility from filing a voluntary petition in bankruptcy if in the determination of the board

of directors of the qualifying utility in the exercise of its fiduciary duty, the filing of its own voluntary petition in bankruptcy would be proper under applicable federal statutory and common law.
(8) A financing order may require the qualifying utility to file with the Commission a periodic report showing the receipt and disbursement of proceeds of environmental control bonds. A financing order may authorize the staff of the Commission to review and audit the books and records of the qualifying utility relating to the receipt and disbursement of proceeds of environmental control bonds. The provisions of this subdivision shall not be construed to limit the authority of the Commission under this chapter to investigate the practices of the qualifying utility or to audit the books and records of the qualifying utility.
(9) In the case of two or more affiliated qualifying utilities that have jointly applied for a financing order as provided in subdivision (1), subsection (c) of this section, a financing order may authorize each affiliated qualifying utility:
(A) to impose environmental control charges on its customers, notwithstanding the fact that the qualifying generating facility at which the environmental control activities are to be conducted is owned, or on the expected date of issuance of the environmental control bonds authorized in the financing order will be owned, by fewer than all of the affiliated qualifying utilities; and
(B) To issue environmental control bonds and to receive and use the proceeds thereof as provided in subdivision (1), subsection (j) of this section, notwithstanding the fact that all or a portion of the proceeds are expected to be used for environmental control activities to be conducted at a qualifying generating facility the ownership of which is as specified in paragraph (A) of this subdivision.
(e) *Application of adjustment mechanism.* --
(1) If the Commission issues a financing order, the Commission shall periodically approve the application of the adjustment mechanism specified in the financing order to correct for any over-collection or under-collection of the environmental control charges and to provide for timely payment of scheduled principal of and interest on the environmental control bonds and the payment and recovery of other financing costs in accordance with the financing order. Application of the adjustment mechanism shall occur at least annually or more frequently as provided in the financing order.
(2) On the same day the qualifying utility files with the Commission its calculation of the adjustment, it shall cause notice of the filing to be given, in the form specified in the financing order, as a Class I legal advertisement in compliance with the provisions of article three, chapter fifty-nine of this code in a newspaper of statewide circulation published each weekday in Kanawha County: *Provided*, That this publication shall be made only if the calculation of the adjustment filed by the qualifying utility with the Commission would result in an increase in the amount of the environmental control charge.
(3) The Commission shall allow interested parties thirty days from the date the qualifying utility filed the calculation of the adjustment within which to make comments, which shall be limited to the mathematical accuracy of the calculation and of the amount of the adjustment. If the Commission determines that a hearing is necessary, the Commission shall hold a hearing on the comments within forty days of the date the qualifying utility filed the calculation of the adjustment.
(4) Each adjustment to the environmental control charge, in an amount as calculated by the qualifying utility but incorporating any correction for mathematical inaccuracy as determined by the Commission at or after the hearing, shall automatically become effective: (i) Sixty days following the date on which the qualifying utility files with the Commission its calculation of the adjustment; or (ii) on any earlier date specified in an order of the Commission approving the application of the adjustment.
(5) No adjustment pursuant to this subsection, and no proceeding held pursuant to this subsection, shall in any way affect the irrevocability of the financing order as specified in subsection (f) of this section.

(f) *Irrevocability of financing order.* --
(1) A financing order is irrevocable and the Commission may not reduce, impair, postpone or terminate the environmental control charges approved in the financing order or impair the environmental control property or the collection or recovery of environmental control revenues.
(2) A financing order may be subsequently amended on or after the date of issuance of environmental control bonds authorized thereunder only: (A) At the request of the qualifying utility; (B) in accordance with any restrictions and limitations on amendment set forth in the financing order; and (C) subject to the limitations set forth in subdivision (1) of this subsection.
(3) No change in the credit rating on the unsecured obligations of a qualifying utility from the credit rating that supported the determination by the Commission required in paragraph (A), subdivision (3), subsection (d) of this section shall impair the irrevocability of the financing order specified in subdivision (1) of this subsection.
(g) *Judicial review.* -- An order of the Commission issued pursuant to subdivision (2), subsection (d) of this section is a final order of the Commission. Any party aggrieved by the issuance of any such order may petition for suspension and review thereof by the Supreme Court of Appeals pursuant to section one, article five of this chapter. In the case of any petition for suspension and review, the Supreme Court of Appeals shall proceed to hear and determine the action as expeditiously as practicable and give the action precedence over other matters not accorded similar precedence by law.
(h) *Effect of financing order.* --
(1) A financing order shall remain in effect until the environmental control bonds issued pursuant to the financing order have been paid in full and all financing costs relating to the environmental control bonds have been paid in full.
(2) A financing order shall remain in effect and unabated notwithstanding the bankruptcy, reorganization or insolvency of the qualifying utility or any affiliate thereof or the commencement of any judicial or nonjudicial proceeding therefor.
(3) For so long as environmental control bonds issued pursuant to a financing order are outstanding and the related environmental control costs and financing costs have not been paid in full, the environmental control charges authorized to be imposed in the financing order shall be nonbypassable and shall apply to:
(A) All customers of the qualifying utility located within the utility service area, whether or not the customers may become entitled by law to purchase electric generation services from a provider of electric generation services other than a qualifying utility; and
(B) Any person or legal entity located within the utility service area that may subsequently receive electric delivery service from another public utility operating in the same service area.
(i) *Limitations on jurisdiction of Commission.* --
(1) If the Commission issues a financing order, the Commission may not, in exercising its powers and carrying out its duties regarding regulation and ratemaking, consider environmental control bonds issued pursuant to the financing order to be the debt of the qualifying utility, the environmental control charges paid under the financing order to be revenue of the qualifying utility, or the environmental control costs or financing costs specified in the financing order to be the costs of the qualifying utility, nor may the Commission determine that any action taken by a qualifying utility that is consistent with the financing order is unjust or unreasonable from a regulatory or ratemaking perspective: *Provided*, That subject to the limitations set forth in subsection (f) of this section, nothing in this subdivision shall: (i) Affect the authority of the Commission to apply the adjustment mechanism as provided in subsection (e) of this section; (ii) prevent or preclude the Commission from investigating the compliance of a qualifying utility with the terms and conditions of a financing order and requiring compliance therewith; or (iii) prevent or preclude the Commission from imposing regulatory sanctions against a qualifying utility for failure to comply with the terms and conditions of a financing order or the requirements of this section.

(2) The Commission may not order or otherwise require, directly or indirectly, any public utility to use environmental control bonds to finance any project, addition, plant, facility, extension, capital improvement, environmental control equipment or any other expenditure.
(3) The Commission may not refuse to allow the recovery of any costs associated with the performance of environmental control activities by a public utility solely because the public utility has elected or may elect to finance the performance of those activities through a financing mechanism other than the issuance of environmental control bonds.
(j) *Duties of qualifying utility.* --
(1) A qualifying utility for which a financing order has been issued shall cause the proceeds of any environmental control bonds issued pursuant to a financing order to be placed in a separate account. A qualifying utility may use the proceeds of the issuance of environmental control bonds for paying environmental control costs and financing costs and for no other purpose.
(2) A qualifying utility for which a financing order has been issued shall annually provide to its customers a concise explanation of the environmental control charges approved in a financing order, as modified by subsequent issuances of environmental control bonds authorized under a financing order, if any, and by application of the adjustment mechanism as provided in subsection (e) of this section. These explanations may be made by bill inserts, website information or other appropriate means.
(3) Environmental control revenues shall be applied solely to the repayment of environmental control bonds and other financing costs.
(4) The failure of a qualifying utility to apply the proceeds of an issuance of environmental control bonds in a reasonable, prudent and appropriate manner or otherwise comply with any provision of this section shall not invalidate, impair or affect any financing order, environmental control property, environmental control charge or environmental control bonds: *Provided*, That subject to the limitations set forth in subsection (f) of this section, nothing in this subdivision shall prevent or preclude the Commission from imposing regulatory sanctions against a qualifying utility for failure to comply with the terms and conditions of a financing order or the requirements of this section.
(k) *Environmental control property.* --
(1) Environmental control property that is specified in a financing order shall constitute an existing, present property right, notwithstanding the fact that the imposition and collection of environmental control charges depend on the qualifying utility continuing to provide electric energy or continuing to perform its servicing functions relating to the collection of environmental control charges or on the level of future energy consumption. Environmental control property shall exist whether or not the environmental control revenues have been billed, have accrued or have been collected and notwithstanding the fact that the value or amount of the environmental control property is dependent on the future provision of service to customers by the qualifying utility. (2) All environmental control property specified in a financing order shall continue to exist until the environmental control bonds issued pursuant to a financing order are paid in full and all financing costs relating to the bonds have been paid in full.
(3) All or any portion of environmental control property may be transferred, sold, conveyed or assigned to any person or entity not affiliated with the qualifying utility or to any affiliate of the qualifying utility created for the limited purposes of acquiring, owning or administering environmental control property or issuing environmental control bonds under the financing order or a combination of these purposes. All or any portion of environmental control property may be pledged to secure the payment of environmental control bonds, amounts payable to financing parties and bondholders, amounts payable under any ancillary agreement and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in or pledge of environmental control property by a qualifying utility or affiliate of a qualifying utility to an affiliate of the qualifying utility, to the extent previously authorized in a financing order, does not require the prior consent and approval of the Commission under section twelve of this article.

(4) If a qualifying utility defaults on any required payment of environmental control revenues, a court, upon application by an interested party and without limiting any other remedies available to the applying party, shall order the sequestration and payment of the environmental control revenues for the benefit of bondholders, any assignee and any financing parties. The order shall remain in full force and effect notwithstanding any bankruptcy, reorganization, or other insolvency proceedings with respect to the qualifying utility or any affiliate thereof.
(5) Environmental control property and environmental control revenues, and the interests of an assignee, bondholder or financing party in environmental control property and environmental control revenues, are not subject to setoff, counterclaim, surcharge or defense by the qualifying utility or any other person or in connection with the bankruptcy, reorganization or other insolvency proceeding of the qualifying utility, any affiliate thereof or any other entity.
(6) Any successor to a qualifying utility shall be bound by the requirements of this section and shall perform and satisfy all obligations of, and have the same rights under a financing order as, the qualifying utility under the financing order in the same manner and to the same extent as the qualifying utility, including, without limitation, the obligation to collect and pay to the person entitled to receive them environmental control revenues.
(l) *Security interests.* -- Except as otherwise provided in this subsection, the creation, perfection and enforcement of any security interest in environmental control property to secure the repayment of the principal of and interest on environmental control bonds, amounts payable under any ancillary agreement and other financing costs are governed by this subsection and not the provisions of chapter forty-six of this code. All of the following shall apply:
(1) The description or indication of environmental control property in a transfer or security agreement and a financing statement is sufficient only if the description or indication refers to this section and the financing order creating the environmental control property. This subdivision applies to all purported transfers of, and all purported grants of liens on or security interests in, environmental control property, regardless of whether the related transfer or security agreement was entered into, or the related financing statement was filed, before or after the effective date of this section.
(2) A security interest in environmental control property is created, valid, and binding at the later of the time: (i) The financing order is issued; (ii) a security agreement is executed and delivered; and (iii) value is received for the environmental control bonds. The security interest attaches without any physical delivery of collateral or other act and the lien of the security interest shall be valid, binding and perfected against all parties having claims of any kind in tort, contract or otherwise against the person granting the security interest, regardless of whether such parties have notice of the lien, upon the filing of a financing statement with the office of the Secretary of State. The office of the Secretary of State shall maintain any such financing statement in the same manner and in the same record-keeping system it maintains for financing statements filed pursuant to article nine, chapter forty-six of this code. The filing of any financing statement under this subdivision shall be governed by the provisions regarding the filing of financing statements in said article.
(3) A security interest in environmental control property is a continuously perfected security interest and has priority over any other lien, created by operation of law or otherwise, which may subsequently attach to the environmental control property unless the holder of any such lien has agreed in writing otherwise.
(4) The priority of a security interest in environmental control property is not affected by the commingling of environmental control revenues with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all environmental control revenues that are deposited in any cash or deposit account of the qualifying utility in which environmental control revenues have been commingled with other funds and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party.

(5) No subsequent order of the Commission amending a financing order pursuant to subdivision (2), subsection (f) of this section, and no application of the adjustment mechanism as provided in subsection (e) of this section, will affect the validity, perfection or priority of a security interest in or transfer of environmental control property.
(m) *Sales of environmental control property.* --
(1) Any sale, assignment or transfer of environmental control property shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title and interest in, to and under the environmental control property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer. A transfer of an interest in environmental control property may be created only when all of the following have occurred: (i) The financing order creating the environmental control property has become effective; (ii) the documents evidencing the transfer of environmental control property have been executed and delivered to the assignee; and (iii) value is received. Upon the filing of a financing statement with the office of the Secretary of State, a transfer of an interest in environmental control property shall be perfected against all third persons, including any judicial lien or other lien creditors or any claims of the seller or creditors of the seller, other than creditors holding a prior security interest, ownership interest or assignment in the environmental control property previously perfected in accordance with this subdivision or subdivision (2), subsection (l) of this section. The office of the Secretary of State shall maintain any such financing statement in the same manner and in the same record-keeping system it maintains for financing statements filed pursuant to article nine, chapter forty-six of this code.
(2) The characterization of the sale, assignment or transfer as an absolute transfer and true sale and the corresponding characterization of the property interest of the purchaser, shall not be affected or impaired by, among other things, the occurrence of any of the following factors:
(A) Commingling of environmental control revenues with other amounts;
(B) The retention by the seller of: (i) A partial or residual interest, including an equity interest, in the environmental control property, whether direct or indirect, or whether subordinate or otherwise; or (ii) the right to recover costs associated with taxes, franchise fees or license fees imposed on the collection of environmental control revenues;
(C) Any recourse that the purchaser may have against the seller;
(D) Any indemnification rights, obligations or repurchase rights made or provided by the seller;
(E) The obligation of the seller to collect environmental control revenues on behalf of an assignee;
(F) The treatment of the sale, assignment or transfer for tax, financial reporting or other purposes;
(G) Any subsequent order of the Commission amending a financing order pursuant to subdivision (2), subsection (f) of this section; or
(H) Any application of the adjustment mechanism as provided in subsection (e) of this section.
(n) *Exemption from municipal taxation.* -- The imposition, collection and receipt of environmental control revenues are not subject to taxation by any municipality of the state under the authority granted to municipalities in sections five and five-a, article thirteen, chapter eight of this code.
(o) *Environmental control bonds not public debt.* -- Environmental control bonds issued pursuant to a financing order and the provisions of this section shall not constitute a debt or a pledge of the faith and credit or taxing power of this state or of any county, municipality or any other political subdivision of this state. Bondholders shall have no right to have taxes levied by the Legislature or the taxing authority of any county, municipality or any other political subdivision of this state for the payment of the principal thereof or interest thereon. The issuance of environmental control bonds does not, directly or indirectly or contingently, obligate the state or a political subdivision of the state to levy any tax or make any appropriation for payment of the principal of or interest on the bonds.
(p) *Environmental control bonds as legal investments.* -- Any of the following may legally invest any sinking funds, moneys or other funds belonging to them or under their control in environmental

control bonds:
(1) The state, the West Virginia Investment Management Board, the West Virginia Housing Development Fund, municipal corporations, political subdivisions, public bodies and public officers except for members of the Public Service Commission.
(2) Banks and bankers, savings and loan associations, credit unions, trust companies, building and loan associations, savings banks and institutions, deposit guarantee associations, investment companies, insurance companies and associations and other persons carrying on a banking or insurance business, including domestic for life and domestic not for life insurance companies; and
(3) Personal representatives, guardians, trustees and other fiduciaries.
(q) *State pledge.* --
(1) The state pledges to and agrees with the bondholders, any assignee and any financing parties that the state will not take or permit any action that impairs the value of environmental control property or, except as allowed under subsection (e) of this section, reduce, alter or impair environmental control charges that are imposed, collected and remitted for the benefit of the bondholders, any assignee, and any financing parties, until any principal, interest and redemption premium in respect of environmental control bonds, all financing costs and all amounts to be paid to an assignee or financing party under an ancillary agreement are paid or performed in full.
(2) Any person who issues environmental control bonds is permitted to include the pledge specified in subdivision (1) of this subsection in the environmental control bonds, ancillary agreements and documentation related to the issuance and marketing of the environmental control bonds.
(r) *Choice of law.* -- The law governing the validity, enforceability, attachment, perfection, priority and exercise of remedies with respect to the transfer of an interest or right or creation of a security interest in any environmental control property, environmental control charge or financing order shall be the laws of the State of West Virginia as set forth in this section and article nine, chapter forty-six of this code.
(s) *Conflicts.* -- In the event of conflict between this section and any other law regarding the attachment, assignment or perfection, or the effect of perfection, or priority of any security interest in or transfer of environmental control property, this section shall govern to the extent of the conflict.
(t) *Effect of invalidity on actions.* -- Effective on the date that environmental control bonds are first issued under this section, if any provision of this section is held to be invalid or is invalidated, superseded, replaced, repealed or expires for any reason, that occurrence shall not affect any action allowed under this section that is taken by the Commission, a qualifying utility, an assignee, a collection agent, a financing party, a bondholder, or a party to an ancillary agreement and any such action shall remain in full force and effect.
(u) *Effectiveness of section.* -- No qualifying utility may make initial application for a financing order after the date which is five years after the effective date of this section. This subsection shall not be construed to preclude any qualifying utility for which the Commission has initially issued a financing order from applying to the Commission: (i) For a subsequent order amending the financing order pursuant to subdivision (2), subsection (f) of this section; or (ii) for approval of the issuance of environmental control bonds to refund all or a portion of an outstanding series of environmental control bonds.
(v) *Severability.* -- If any subsection, subdivision, paragraph or subparagraph of this section or the application thereof to any person, circumstance or transaction is held by a court of competent jurisdiction to be unconstitutional or invalid, the unconstitutionality or invalidity shall not affect the constitutionality or validity of any other subsection, subdivision, paragraph or subparagraph of this section or its application or validity to any person, circumstance or transaction, including, without limitation, the irrevocability of a financing order issued pursuant to this section, the validity of the issuance of environmental control bonds, the imposition of environmental control charges, the transfer or assignment of environmental control property or the collection and recovery of environmental control revenues. To these ends, the Legislature hereby declares that the provisions of

this section are intended to be severable and that the Legislature would have enacted this section even if any subsection, subdivision, paragraph or subparagraph of this section held to be unconstitutional or invalid had not been included in this section.

CHAPTER 46. UNIFORM COMMERCIAL CODE.

ARTICLE 9. SECURED TRANSACTIONS; SALES OF ACCOUNTS AND CHATTEL PAPER.

SUBPART 2. APPLICABILITY OF ARTICLE.

§46-9-109. Scope.

(a) *General scope of article.* -- Except as otherwise provided in subsections (c) and (d) of this section, this article applies to:

(1) A transaction, regardless of its form, that creates a security interest in personal property or fixtures by contract;

(2) An agricultural lien;

(3) A sale of accounts, chattel paper, payment intangibles or promissory notes;

(4) A consignment;

(5) A security interest arising under section 2-401, 2-505, 2-711(3) or 2A-508(5) as provided in section 9-110; and

(6) A security interest arising under section 4-210 or 5-118.

(b) *Security interest in secured obligation.* -- The application of this article to a security interest in a secured obligation is not affected by the fact that the obligation is itself secured by a transaction or interest to which this article does not apply.

(c) *Extent to which article does not apply.* -- This article does not apply to the extent that:

(1) A statute, regulation or treaty of the United States preempts this article; or

(2) The rights of a transferee beneficiary or nominated person under a letter of credit are independent and superior under section 5-114.

(d) *Inapplicability of article.* -- This article does not apply to:

(1) A landlord's lien, other than an agricultural lien;

(2) A lien, other than an agricultural lien, given by statute or other rule of law for services or materials, but section 9-333 applies with respect to priority of the lien;

(3) An assignment of a claim for wages, salary or other compensation of an employee;

(4) A sale of accounts, chattel paper, payment intangibles or promissory notes as part of a sale of the business out of which they arose;

(5) An assignment of accounts, chattel paper, payment intangibles or promissory notes which is for the purpose of collection only;

(6) An assignment of a right to payment under a contract to an assignee that is also obligated to perform under the contract;

(7) An assignment of a single account, payment intangible or promissory note to an assignee in full or partial satisfaction of a preexisting indebtedness;

(8) A transfer of an interest in or an assignment of a claim under a policy of insurance, other than an assignment by or to a health care provider of a health care-insurance receivable and any subsequent assignment of the right to payment, but sections 9-315 and 9-322 apply with respect to proceeds and priorities in proceeds;

(9) An assignment of a right represented by a judgment, other than a judgment taken on a right to payment that was collateral;

(10) A right of recoupment or set-off, but:

(A) Section 9-340 applies with respect to the effectiveness of rights of recoupment or set-off against deposit accounts; and
(B) Section 9-404 applies with respect to defenses or claims of an account debtor;
(11) The creation or transfer of an interest in or lien on real property, including a lease or rents thereunder, except to the extent that provision is made for:
(A) Liens on real property in sections 9-203 and 9-308;
(B) Fixtures in section 9-334;
(C) Fixture filings in sections 9-501, 9-502, 9-512, 9-516, and 9-519; and
(D) Security agreements covering personal and real property in section 9-604;
(12) An assignment of a claim arising in tort, other than a commercial tort claim, but sections 9-315 and 9-322 apply with respect to proceeds and priorities in proceeds;
(13) An assignment of a deposit account in a consumer transaction, but sections 9-315 and 9-322 apply with respect to proceeds and priorities in proceeds;
(14) A transfer by a government or a governmental unit; or
(15) A transfer of security interest in any interest or right, or any portion or any interest or right in any environmental control property, environmental control charge or financing order as each term is defined in section four-e, article two, chapter twenty-four of this code.