FEDERAL TAX ISSUES RELATING TO RESTRUCTURING OF THE ELECTRIC POWER INDUSTRY

Scheduled for a Public Hearing

Before the

SUBCOMMITTEE ON LONG-TERM GROWTH AND DEBT REDUCTION

of the

SENATE COMMITTEE ON FINANCE

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INTRODUCTION

This document,[1] prepared by the staff of the Joint Committee on Taxation, provides a description of present-law Federal tax provisions relating to the electric power industry and a discussion of related legal and economic issues. The Subcommittee on Long-Term Growth and Debt Reduction of the Senate Committee on Finance has scheduled a public hearing on this subject on October 19, 1999.

This document provides descriptive information and data on the principal current Federal tax provisions specifically relating to the electric power industry, including matters for investor-owned, publicly-owned, and cooperatively-owned utilities and for non-utility generators and other participants in the electric power industry.

Part I of the document is a summary. Part II is a description of present-law Federal tax provisions affecting electric service providers. Part III is a discussion of economic and tax issues associated with electric power industry restructuring. An Appendix provides data relating to Figures 1-4 in the document.

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[1] This document may be cited as follows: Joint Committee on Taxation, *Federal Tax Issues Relating to Restructuring of the Electric Power Industry* (JCX-72-99), October 15, 1999.

The document revises and updates an earlier publication: Joint Committee on Taxation, *Federal Income Tax Issues Arising in Connection with Proposals to Restructure the Electric Power Industry* (JCS-20-97), October 17, 1997.

I. SUMMARY

In 1998, production and use of electricity comprised 36 percent of total energy consumption in the United States, and in 1997 sales of electricity comprised 2.7 percent of gross domestic product ("GDP"). In residential and commercial non-transportation uses, electricity comprised 70 percent of total energy use, while electricity accounted for 34 percent of the energy used by industry. The residential sector is the largest end-user of electricity, having consumed 35 percent of all electricity consumed in 1998. The industrial sector consumed 33 percent of electricity, while commercial users consumed 29 percent.

The electric power industry generally is comprised of three types of electric utilities--investor-owned utilities ("IOUs"), publicly owned utilities ("public power"), and electric cooperatives ("co-ops")--and of certain non-utility ("independent power") producers. In 1997, IOUs provided 76 percent of final electricity sales, public power 15 percent, and co-ops 8 percent. The provision of electricity involves four distinct functions: generation, transmission, distribution, and retail sales. "Generation" involves the creation of electricity. The "transmission" of electricity refers to the transportation of electricity from generation sites to distribution centers. The "distribution" of electricity refers to the transportation of electricity from distribution centers to customers' homes and businesses. The "retailing" function involves metering and billing final customers. Retailing also may require the retailer to contract with generators and owners of transmission and distribution systems for the provision of electricity. Most electricity is provided by vertically integrated suppliers that perform each of the four functions of generation, transmission, distribution, and retailing.

Current efforts to restructure the electric power industry by eliminating or reducing both its vertical integration and rate regulation aspects raise significant Federal tax and related economic issues. This pamphlet describes present-law Federal tax provisions applicable to the electric power industry and discusses major issues raised by these restructuring proposals.

A. Tax Provisions Affecting Both Investor-Owned and Municipal Electric Service Providers: Tax-Exempt Financing

Interest on debt incurred by States or local governments is excluded from the income of the lender (“bondholder”) if the proceeds of the borrowing are used to carry out governmental functions of those entities or the debt is repaid with governmental funds of those entities. Interest on bonds that nominally are issued by States or local governments, the proceeds of which are used (directly or indirectly) by a private person and payment of which is derived from funds of such a private person ("private activity bonds"), is taxable unless the purpose of the borrowing is approved specifically in the Internal Revenue Code (the "Code") or in another provision of a revenue Act. The term "private person" generally includes the Federal Government and all other individuals and entities other than States or local governments.

The provision of electric service (generation, transmission, distribution, and retailing) is a governmental activity eligible for financing with governmental tax-exempt bonds when the financed facilities are used by or paid for by a State or local government entity (e.g., by public power). As with other governmental activities, public power also is eligible for limited tax-exempt financing of working capital costs (e.g., salaries of employees and similar expenses). Except as described in Part II, private IOU and co-op electric service providers generally are not eligible for tax-exempt financing of their facilities.

If public power entities elect to participate in State open access industry restructuring plans where public and private business electric systems are integrated, interest on outstanding tax-exempt bonds of the public power entities may become retroactively taxable unless the issuers of the bonds qualify for and issuers avail themselves of certain administrative relief provided in Treasury Department regulations. In addition, public power facilities that are used in a manner violating the Code's restrictions on the issuance of tax-exempt bonds to benefit private persons will be ineligible for future tax-exempt financing.

B. Additional Tax Provisions Affecting Investor-Owned Utilities

Cost recovery of property used in the production, transmission, and distribution of electricity

A taxpayer generally must capitalize the cost of property used in a trade or business and is allowed to recover the cost over time through allowances for depreciation and amortization. Cost recovery rules for ratemaking and Federal income tax purposes are important to electric utilities because of the capital-intensive nature of the industry. The methods used by IOUs generally recover the cost of public utility property more rapidly for Federal income tax purposes than do the methods used for ratemaking or financial accounting purposes.

In order for public utility property to be eligible for the more favorable depreciation allowances available for Federal income tax purposes (relative to the depreciation allowances used for ratemaking or financial statement purposes), the tax benefits of accelerated depreciation must be "normalized" in setting rates charged by utilities to customers and in reflecting operating results in regulated books of account. The normalization method of accounting generally spreads the tax benefits of accelerated depreciation over the regulatory life of the property and results in higher utility rates in the early years and lower utility rates in the later years than otherwise would have occurred.

Rate regulation typically guarantees the recovery of both the amount invested in property to be used in the business as well as a sufficient return on the investment. So long as these guarantees exist, electric utilities are able to invest in property without regard to the fair market value of such property in an unregulated environment or the amount of income such property could earn if used to produce power for sale at competitive rates. In certain instances, utilities, with the knowledge of the appropriate regulatory body, may have invested in property whose cost could only be justified by the presence of a guaranteed return.[2]

Restructuring of the electric power industry could adversely affect the value of property that was placed in service in a regulated environment. If the return on the investment in the property is no longer guaranteed through rate regulation, the value of the property will be determined solely by the amount of income that the property can earn producing power at competitive rates. On average, it is anticipated that competition will reduce the rates consumers pay for electric services, and thereby reduce the amount of income that the property can earn from producing power. Such a reduction in the rates for electric services is expected, on average, to decrease the value of the existing assets used to produce such services.[3]

The extent to which the book or regulatory value of electric utility property exceeds its fair market value after restructuring is sometimes referred to as a "stranded cost." These costs are considered "stranded," because the electric service provider had anticipated recovering the full cost of the property under the ratemaking process when the property was placed in service, and such recovery is unlikely in an unregulated environment. Proposals to restructure the electric power industry often address the difficult issue of how to allow a utility to recover its stranded costs.

There are no special tax provisions that allow for the immediate recovery of stranded costs. In order to recover the adjusted basis of depreciable property, the taxpayer generally must dispose of the property, abandon it, or show its obsolescence. In the absence of such an event, electric service providers will continue to depreciate the property in the same manner after the restructuring of the industry as before the restructuring and will recover any stranded cost over the remaining depreciable life of the property.

The restructuring of the electric power industry also raises several issues with respect to the normalization method of accounting. If an entire electric utility is deregulated, IOUs no longer will be subject to ratemaking processes, and thus the normalization requirements of the Code will no longer apply. If only a portion of the electric utility's services are deregulated (e.g.,

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[2] A regulated utility may have been obligated to provide electricity to its customers on demand. To meet this obligation, the utility's generating capacity (either owned or contracted) must be based on maximum projected demand, which may exceed the capacity the utility would have determined to be optimal in an unregulated environment.

[3] It is possible that some regulated assets in regions with low cost electricity could increase in value if their output is able to be sold to other regions at prices higher than those in their present regulated market. Additionally, the value of underutilized assets that are already outside the regulatory environment could be increased by the proposed restructuring of the electric power industry, because the market for their output would be increased.

the generation and transmission services but not the distribution services), then a portion of the utility's property will remain public utility property subject to the normalization requirements, and the remainder will not.

The method by which the electric power industry is restructured may affect the application of the normalization method of accounting. If a public utility commission decides to transition into deregulation, the determination of whether or not certain property is public utility property may be difficult. For example, if a public utility commission allows an IOU to recover a portion of the stranded costs applicable to certain deregulated property, it is unclear the extent to which such property is public utility property subject to the normalization method of accounting.

Other tax provisions of industry concern

A number of additional provisions affect IOUs, either because they provide rules specifically applicable to utilities, or because they govern the Federal income tax treatment of transactions in which IOUs are likely to engage.[4] Restructuring of the electric power industry could affect a number of these provisions. Some provisions, such as the provision allowing for the deduction of certain deposits to nuclear decommissioning funds, assume a regulatory framework. If a plan of restructuring requires the separation of the businesses of generating and distributing electricity, Federal income tax rules applicable to forced sales may apply. Provisions governing other transactions may not be affected directly but may become significantly more common (such as cancellation of supply contracts) or less common (such as conservation payments) as a result of restructuring.

Deferred tax accounts: financial, regulatory, and tax accounting issues

A deferred tax account is required whenever temporary differences exist between the Federal income tax accounting and financial accounting treatment of an item. When the difference will result in amounts taxable in the future, a deferred tax liability is created. When the difference will result in amounts deductible in the future, as well as when there is an anticipated reduction in future tax liability attributable to the carryforward of items such as net operating losses and tax credits, a deferred tax asset is created. Although it may create numerous indirect effects on the deferred tax accounts, restructuring is not expected to affect the balances in these accounts directly.

General corporate restructuring tax issues

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[4] Except for possible activities not exempt from tax under Code section 115, tax provisions other than those governing tax-exempt financing generally do not affect public power entities, because under section 115, public power is exempt from all Federal income tax as a State or local government entity.

Electric power industry restructuring could result in significant reorganization of businesses currently owned by IOUs. For example, an IOU that has owned generation, transmission, and distribution facilities may dispose of some or all of these facilities. In some cases, all the assets and activities of a segment of the business may be disposed of. In other cases, businesses and assets might be combined with those of other service providers in new ventures. Some ventures also may involve transfers or participation between tax-exempt and taxable entities.

The disposition or combination of businesses and assets can be structured in various ways, producing various tax results. Assets or businesses may be disposed of for cash or otherwise in taxable transactions. If certain continued stock ownership requirements are met, transactions also may be structured in a form that is not immediately taxable. Partnerships also may be utilized to combine corporate activities or to readjust the future interests of contributing partners in those activities. There may be limitations on the future use of existing losses at the corporate level if more than 50 percent of the corporate stock changes hands. Also, certain acquisitions that are part of a plan or series of related transactions may result in corporate level tax in connection with certain corporate "spin-off" transactions, in which a corporate business is distributed to shareholders as a separate corporation. Some of the corporate restructuring described above may be inhibited by the Public Utility Holding Company Act of 1935, which restricts combined ownership of IOUs in different States.

Generally, the various corporate reorganization provisions of present law apply to IOUs in the same manner as other entities. Special dividends paid and dividends received deduction provisions that relate to certain public utility preferred stock issued before October 1, 1942, or issued after that date for specified purposes, might be implicated in certain types of readjustments.

C. Tax Provisions Affecting Electric Cooperatives

Under present law, a rural electric cooperative is exempt from Federal income tax if at least 85 percent of the cooperative's income consists of amounts collected from members for the sole purpose of meeting losses and expenses of providing service to the members. With electric power industry restructuring, it is not clear whether a rural electric cooperative can be assured that it will receive at least 85 percent of its income from its members, because fees that the cooperative receives for wheeling electricity through its system and sales of surplus electricity will not be income from members.

D. Special Energy Tax Incentive Provisions

Under present law, tax credits are allowed for (1) the production of electricity from either qualified wind energy or qualified "closed-loop" biomass facilities, and (2) a portion of the cost of qualified solar and geothermal energy property.

The production credit for electricity produced from wind and closed-loop biomass facilities equals 1.5 cents (which is adjusted for inflation)[5] per kilowatt hour of electricity produced from these qualified sources during the 10-year period after the facility is placed in service. The credit is available for qualified facilities placed in service after December 31, 1993 (December 31, 1992, in the case of a facility using closed-loop biomass to produce electricity), and before July 1, 1999. The amount of the credit is reduced by an amount which bears the same ratio to the amount of the credit as the amount, by which a reference price for the calendar year of sale exceeds eight cents (which is adjusted for inflation), bears to three cents.[6]

The credit for solar and geothermal energy property is a nonrefundable business energy tax credit equal to 10 percent of the cost of qualified solar and geothermal energy property. This credit is permanent.

E. Economic and Tax Issues Associated with Electric Power Industry Restructuring

Economic issues raised by restructuring of the electric power industry

Policymakers long have viewed the existence of natural monopoly as justification for regulation or public provision of electricity to protect consumer interests from monopoly pricing. More recently, analysts have argued that to the extent that the provision of electricity has the characteristics of natural monopoly, it is not because there are the characteristics of natural monopoly present in each of the four functions (generation, transmission, distribution, and retailing). They note that economies of scale are not so great in generation as to necessitate one generator per region. Likewise, they argue that the retail sale, metering, and billing of electricity does not require a single metering and billing agent. This has led some to suggest that either the generation or retailing functions of the provision of electricity could be restructured and opened to market competition to the benefit of consumers.

The rationale for restructuring is that competitive markets provide goods and services at the least cost to consumers. By injecting competition into either the generation function or retailing function, some of the inefficiencies of the present system may be eliminated with the benefits ultimately flowing to consumers. Moving from regulated, average cost pricing, to competitive market pricing generally will change consumers' electric bills. There is no guarantee that *all* consumers' bills will fall. Some may view these benefits of restructuring as being

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[5] The inflation-adjusted renewable electricity production credit is 1.7 cents per kilowatt hour in 1999. Notice 99-26, 1999-21 I.R.B. 4.

[6] The IRS determined that the reference prices for calendar year 1999 do not exceed eight cents; therefore, the phaseout of the credit does not apply for 1999. Notice 99-26.

distributed inequitably. On the other hand, the current distribution of prices across consumers may be viewed as inequitable.

If restructuring leads to changes in prices or new entry to the market for the provision of electricity, the value of existing assets used to provide electricity may change. Some may view the resulting pattern of gains and losses in asset values as inequitable. In a regulated environment, where rates have been set on a cost of service basis, utilities have had the assurance of recapturing asset values by means of a regulatorily established "fair" rate of return that is based on the historical costs of these investments. In the competitive environment, it is widely acknowledged that prices for electricity to some consumers will be lower than those currently set through the regulatory process, and that the market value of certain assets will be lower than their historical costs on the books for ratemaking purposes. As described above, the difference in the market value of these assets relative to their value in the ratemaking process has commonly come to be called "stranded costs." Many observers feel that the recovery of stranded costs should be allowed on the grounds that there was a "regulatory compact" that provided that "prudently" incurred costs would be recoverable in the ratemaking process in exchange for the provision of service at regulated rates to everyone in the service territory.

While restructuring creates "stranded costs," the true economic costs that give rise to "stranded costs" have already been incurred. That is, stranded costs are not a true aggregate economic cost of restructuring, but rather represent simply a calculation of the value of the true economic losses from past investments. From the standpoint of society as a whole, they are irretrievable losses, and the debate over stranded costs is simply a debate over who should bear these costs in a transition to competition. Whether the shareholders and bondholders of the IOUs, co-ops, and public power entities should bear these costs, or whether the existing customer base on behalf of whom the costs were incurred or future customers, should bear these costs, is a debate as to what is "fair." However, the manner in which these costs are assigned, as opposed to whom they are allocated, might have important implications for the economically efficient operation of electricity markets.

Other tax issues raised by the restructuring of the electric power industry

Public power entities are not subject to the corporate income tax and may use tax-exempt bonds to help finance their investments. Cooperatives, which are owned by the patrons of the system, are accorded pass-through status for Federal income tax purposes. In certain circumstances, the dividends received by individual taxpayers may be excludable from taxable income at the member level as well as excludable at the entity level. Cooperatives' investments also benefit from favorable loans from the Federal Government. The cost of capital of both types of entities is lower than it would be if they were subject to corporate income tax.

Because tax-exempt financing lowers the cost of debt capital, entities that receive tax-exempt financing may rely more heavily on debt finance than other electric service providers. Loss of the ability to use tax-exempt financing may cause the affected entities to adjust their financial structure in the long run. If certain electric service providers were permitted to retain their ability to receive tax-exempt financing in a competitive marketplace, those providers might have a considerable cost advantage over other competitors in a deregulated market.

Similarly, the cost of both equity and debt capital may be more favorable for cooperatives than that of many IOUs. One of the policy reasons behind the creation of these favorable financing sources for cooperatively owned utilities was to offset the higher cost of providing service in certain areas. These high costs generally were attributable to the distribution and retailing of the electricity in rural areas, rather than in the generation of electricity. If, under a restructuring plan, cooperatively owned electric power generating facilities retain favorable costs of equity and debt capital they may gain a cost advantage over other competing facilities.

The Code provides certain income tax incentives for the production of electricity by specified means, such as by wind, solar, or "closed loop" biomass facilities. Such special provisions may be justified on various grounds (*e.g.*, they produce less pollution, reduce U.S. reliance on foreign energy), but these provisions represent a departure from the purely competitive model, where prices are determined solely by the workings of the market place, rather than being influenced by government intervention that favors particular activities. If these special tax incentives are designed to overcome specific market failures, they may result in more socially efficient economic outcomes. These special tax incentives are not part of the "regulatory framework," however, and they are not necessarily jeopardized by the restructuring proposals under consideration.

Under present law, special tax treatment is allowed for set-asides for the future decommissioning of nuclear power plants. The rationale for this provision of current law is to assure that there is adequate funding available for the high cost of decommissioning these plants at the end of their useful life and to allow matching of the costs of decommissioning a nuclear power plant with the revenue the plant generates. Under competition, there may still be a compelling public policy rationale for some form of required, deductible set-asides for the decommissioning of the nuclear plants.

II. FEDERAL TAX PROVISIONS AFFECTING ELECTRIC SERVICE PROVIDERS

A. Tax Provisions Affecting Both Investor-Owned and Municipal Electric Service Providers: Tax-Exempt Financing

1. Present Law

In general

Interest on debt[7] incurred by States or local governments is excluded from income if the proceeds of the borrowing are used to carry out governmental functions of those entities or the debt is repaid with governmental funds (sec. 103).[8] Interest on bonds that nominally are issued by States or local governments, but the proceeds of which are used (directly or indirectly) by a private person and payment of which is derived from funds of such a private person ("private activity bonds") is taxable, unless the purpose of the borrowing is approved specifically in the Code or in another provision of a revenue Act. The term "private person" generally includes the Federal Government and all other individuals and entities other than States or local governments.[9]

The general structure of the rules for determining whether a tax-exempt bond is a governmental or a private activity bond was established in 1968. The Tax Reform Act of 1986

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[7] Hereinafter referred to as "State or local government bonds," even though not all tax-exempt debt results in the issuance of a formal bond (e.g., installment sales agreements are treated as bonds).

[8] Interest on this debt is included in calculating the "adjusted current earnings" preference of the corporate alternative minimum tax.

[9] Interest on Federal debt is taxable. However, unlike most State or local government debt, Federal debt benefits from the Federal Government's guarantee of repayment. The Code includes limited exceptions allowing the combination of these benefits, generally for programs that were in existence before enactment of the Tax Reform Act of 1984.

One such exception allows certain tax-exempt financing of State or local government facilities that transmit and distribute electric power supplied by the Bonneville Power Administration (the “BPA”), a Federal instrumentality. In addition, section 1316(d) of the Tax Reform Act of 1986 codified a prior-law Treasury Department regulation which treated the BPA as a State or local government unit rather than as a Federal entity. These exceptions are unique to the BPA; other Federal power agencies are treated as Federal entities and are not permitted to benefit from tax-exempt financing or to guarantee such financing.

(the "1986 Act") further restricted the amount of private use that may be financed before a State or local government bond is classified as a private activity bond, and enacted extensive additional restrictions on tax-exempt financing generally.

The provision of electric service (generation, transmission, distribution, and retailing) is an activity eligible for financing with governmental tax-exempt bonds when the financed facilities are used by or paid for by a State or local governmental entity (e.g., "public power")[10] As with other governmental activities, public power entities also are eligible for limited tax-exempt financing of working capital costs (e.g., salaries of employees and similar expenses). Except as described below, IOUs and co-ops generally are not eligible for tax-exempt financing of their facilities. With the exception of certain charitable organizations that are described in Code section 501(c)(3), private businesses are not eligible to finance working capital costs with tax-exempt bonds (except with proceeds of a permitted five-percent "bad money" portion of a bond issue which may be used for any type of expenditure).

Classification of bonds as private activity bonds

Present law provides two tests for determining whether a State or local government bond is, in substance, a private activity bond (sec. 141(b) and (c)).

Private business test.--Private business use and private payments result in State or local government bonds being private activity bonds if both parts of a two-part private business test are violated–

(1) More than 10 percent of the bond proceeds is to be used (directly or indirectly) by a private business (the "private business use test"); and

(2) More than 10 percent of the debt service on the bonds directly or indirectly is secured by an interest in property to be used in a private business use or is to be derived from payments in respect of such property (the "private payment test").

The 10-percent private business use and payment threshold is reduced to five percent for private business uses that are unrelated to a governmental purpose also being financed with proceeds of the bond issue. For example, a privately operated cafeteria in a government office building financed as part of the building's construction could represent a related private business use. On the other hand, a separate, private manufacturing facility financed with proceeds of the

[10] Code section 115 also exempts the income that States and local governments derive from the operation of public power systems as governmental activities. Questions may arise regarding continued tax-exemption of income of public power if these entities enter into private business arrangements (*e.g.,* preferential customer contracts or joint-venture power marketing arrangements) in competition with IOUs.

same bond issue would constitute an unrelated private business use of bond proceeds. Additionally, as described more fully below, since enactment of the 1986 Act, the 10-percent private business use and private payment thresholds are phased-down for larger bond issues for the financing of certain "output" facilities. The term output facility includes electric generation, transmission, and distribution facilities.

Private business use generally includes any use by a business entity (including the Federal Government) which occurs pursuant to terms not generally available to the general public. For example, if bond-financed property is leased to a private business (other than pursuant to certain short-term leases for which safe harbors are provided under Treasury Department regulations), bond proceeds used to finance the property are treated as used in a private business use, and rental payments are treated as securing the payment of the bonds. Similarly, in the case of public power entities, if output of an electric generating plant or transmission or distribution facilities is provided to a private business on terms not generally available to other customers of the entity, an allocable portion of bonds financing the facilities is treated as used in a private business use and as secured by the payments from the private business.[11]

Private business use also can arise when a governmental entity contracts for the operation of a governmental facility by a private business under a management contract that does not satisfy Treasury Department regulatory safe harbors regarding the types of payments made to the private operator and the length of the contract.[12] These rules require public power entities to restrict the period of contracts with private businesses as well as the aggregate amount of electric

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[11] See, Joint Committee on Taxation, *General Explanation of the Tax Reform Act of 1986*, JCS-10-87 (May 4, 1987), stating as follows:

> The determination of who uses bond proceeds or bond-financed property generally is made by reference to the ultimate user of the proceeds or property. . . . [B]ond proceeds used to satisfy contractual obligations undertaken in connection with general governmental operations, such as payment of government salaries, or to pay legal judgments against a governmental unit, are not treated as used in the business of the payee. This is to be contrasted with the indirect nongovernmental private use of bond proceeds that occurs when a government contracts with a nongovernmental person to supply that person's trade or business with a service (*e.g.*, electric energy) on a basis different from that on which the service is provided to the public generally or to finance property used in that person's business (*e.g.*, a manufacturing plant). In both of these instances a nongovernmental person is considered to use the bond proceeds other than as a member of the general public. (p. 1160)

[12] See Treas. reg. sec. 1.141-3(b)(4) and Revenue Procedure 97-13, 1997-1 C.B. 632.

service provided to private businesses on terms that are not generally available to customers of the entity, if interest on their bonds is to remain tax-exempt.

Private loan test.--The second standard for determining whether a State or local government bond is a private activity bond is whether an amount exceeding the lesser of (1) five percent of the bond proceeds or (2) $5 million is used directly or indirectly to finance loans to private persons. Private loans include both business and other (*e.g.*, personal) uses and payments by private persons; however, in the case of business uses and payments, all private loans also constitute private business uses and payments subject to the private business test.

Present law provides that the substance, rather than the form, of a transaction governs in determining whether a transaction gives rise to a private loan. In general, any transaction which transfers tax ownership of property to a private person is treated as a loan. In the context of electric facilities, longer-term contracts for the sale of electricity may violate the private loan test, because these contracts have the substantive characteristics of a loan.

Special legislative rules for tax-exempt financing of governmental "output" facilities

In addition to the general private business use and payment tests, the Code includes three specific provisions governing the issuance of governmental tax-exempt bonds to finance electric service facilities.

$15 million limit on private business use.--As stated above, the 1986 Act provided an additional restriction on private business use of State or local government bonds whose proceeds are to be used to finance "output" facilities." Output facilities include, *inter alia*, facilities for electric and gas generation, transmission, and distribution. A bond is treated as issued to finance an output facility (and subject to this restriction) if five percent or more of the proceeds is to be used with respect to any output facility. Under this restriction, the 10-percent private business use and private payment tests in substance are phased down for facilities that receive more than $15 million in tax-exempt bond financing.[13] Significantly, unlike most tax-exempt bond restrictions, which are determined on a bond-issue by bond-issue basis, this restriction is measured by reference to all outstanding tax-exempt financing from which a facility benefits.

Special rules disregarding certain private business use under the private activity bond tests.--The 1986 Act further provided that certain sales of electric power by public power entities to private businesses generally are disregarded in applying the private business and private loan tests. For example, that Act allows the presence of a nongovernmental person acting solely as a

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[13] Before enactment of the 1986 Act, Treasury Department regulations disregarded private business use of output facilities by users whose use totaled three percent or less. The 1986 Act directed Treasury to modify this rule to reduce this three-percent use threshold. See, Treas. reg. sec. 1.141-7T(f)(1).

conduit for exchange of electric output among *governmentally* owned and operated public power entities to be disregarded. In addition, exchange agreements that provide for "swapping" of electricity between governmentally owned and operated entities and IOUs do not give rise to private business use when (1) the "swapped" amounts are approximately equal over a period of one year or less, (2) the electricity is swapped pursuant to an arrangement which does not involve output-type contracts, *and* (3) the purpose of the arrangements is to enable the parties to satisfy differing peak load demands or to accommodate temporary outages.[14] Finally, the legislative history of the 1986 Act provides that "spot sales" of excess power capacity for temporary periods not exceeding 30 days do not violate the private business tests.

Bonds for acquisition of existing output property per se private activity.--In general, any bond with respect to which five percent or more ($5 million if less) of the proceeds is to be used, directly or indirectly, by a governmental entity to acquire existing output property is *per se* a private activity bond.[15] As such, interest on the bond is taxable, unless the use of the acquired facility satisfies the provisions applicable to tax-exempt private activity bonds for the local furnishing of electricity, including receipt of an allocation of the applicable State's annual private activity bond volume authority (described below). The two-county (or a city and a contiguous county) service area requirement that applies to facilities for the local furnishing of electricity does not apply in this circumstance. There are two exceptions to these requirements. First, the restriction does not apply to bonds for the acquisition of existing facilities that will provide service in a "qualified service area" of the issuer. A qualified service area is defined as an area throughout which the acquiring entity has provided electric service for at least the 10-year period preceding the date of the acquisition. Second, the restriction does not apply to bonds issued to acquire existing output property to be used in a "qualified annexed area" of a public power entity. The term qualified annexed area includes only areas (1) that are contiguous to existing service areas, (2) that are annexed for general governmental purposes, and (3) the size of which does not exceed 10 percent of the public power entity's service area before the annexation occurs.

Treasury Department regulations relating to governmental output facility financing

On December 30, 1994, the Treasury Department issued proposed regulations relating to the Code's private business and private loan tests (the "1994 Proposed Regulations"). The 1994 Proposed Regulations included provisions relating to the special legislative rules applicable to governmental bonds used to finance output facilities (Prop. Treas. reg. secs. 1.141-7 and 1.141-8).

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[14] See, *General Explanation of the Tax Reform Act of 1986*, p. 1164.

[15] The 1987 legislation which contained this provision also included a permanent transition rule allowing the Long Island Power Authority to issue governmental tax-exempt bonds for the acquisition of the Long Island Lighting Company ("LILCO") and conversion of that electric utility from a private investor-owned utility to a public power entity. This transaction subsequently was consummated.

On January 10, 1997, the Treasury Department adopted final regulations (the "1997 Final Regulations") on most of the issues addressed by the 1994 Proposed Regulations; however, the Treasury did not include the 1994 proposals interpreting the special rules affecting output facilities. In the preamble to the 1997 Final Regulations, the Treasury stated that it was not adopting final regulations on these rules in order to permit further consideration of issues raised by non-tax regulatory changes affecting the electric power industry.

Subsequently, on January 21, 1998, the Treasury Department issued additional temporary and proposed regulations (the "1998 Temporary Regulations") creating new, non-statutory safe harbors for transactions that may occur in connection with public power participation in electric industry restructuring plans. The 1998 Temporary Regulations are effective for bonds issued during the three-year period beginning on February 23, 1998. In addition, the 1998 Temporary Regulations provide an election under which State or local government bond issuers may apply the regulations to bonds issued before that date.

The 1994 Proposed Regulations.--With regard to the $15 million limit on private business use of output facilities, the 1994 Proposed Regulations interpreted the term "facility" as a single "project." Facilities having different purposes or serving different customer bases generally would not have been treated as part of the same project (e.g., transmission v. distribution facilities or wholesale v. retail facilities). Subject to certain aggregation and anti-abuse provisions, property that was owned by unrelated persons (or financed with bonds of different issuers) would not have been treated as a single project. Further, generating facilities would not have been treated as a single facility if (1) the facilities were not located at the same site or (2) in the case of facilities at the same site, separate generating units were placed in service more than three years apart. A similar two-year placed-in-service rule would have applied to transmission facilities.

The 1994 Proposed Regulations provided guidance on the application of the special private business and loan restrictions to output facilities. In general, the 1994 Proposed Regulations would have treated as private business use and payment the transfer of electricity pursuant to arrangements which have "the effect of transferring to . . . nongovernmental persons substantial benefits of owning facilities and substantial burdens of paying the debt service on bonds used (directly or indirectly) to finance the facilities." These arrangements were defined to include both take-or-pay contracts and requirements contracts.

The 1994 Proposed Regulations also incorporated the legislative safe harbors described above for certain electricity pooling, exchange, and spot sale arrangements. In addition, the Treasury Department proposed to create, by administrative action, a safe-harbor exception from the prohibition on post-bond-issuance deliberate actions that violate the private business and private loan tests. This safe-harbor would have adopted rules similar to those of a statutory provision governing wheeling of electricity by persons engaged in the local furnishing of electricity, described below.

The 1998 Temporary Regulations.–The 1998 Temporary Regulations include a general rule that, if an arrangement provides a private business user with rights to bond-financed property that are different from rights of the general public, the private use is counted under the 10-percent (and $15 million) limits described above. However, in the case of certain public power bonds, the 1998 Temporary Regulations create special exceptions pursuant to which certain transactions entered into to facilitate an issuer's participation in open access arrangements are not treated as giving rise to private business use or as post-issuance deliberate actions increasing the amount of private business use beyond that allowed under the Code.

The first such exception provides that contracts of up to three years duration for the sale to a nongovernmental person of excess electric output resulting from participation in an open access arrangement are not treated as private business use under certain circumstances (Temp. Treas. reg. sec. 1.141-7T(f)(4)). The purpose of the sale must be to mitigate the costs of existing plants that the utilities no longer can recover as a result of competition ("stranded costs"). Issuers benefiting from the rule may not make tax-exempt-bond-financed expenditures to increase the generating capacity of their systems during the term of the contract; however, they may continue to benefit both from all of their outstanding tax-exempt bonds and from newly issued bonds that are not used to increase capacity. Further conditions of this output contract exception are that issuers must offer non-discriminatory open access transmission tariffs for the use of their system under Federal Energy Regulatory Commission ("FERC") rules, and they must use any stranded cost recovery under the contracts to redeem bonds "as promptly as is reasonably practical."

The 1998 Temporary Regulations also include two new exceptions under which private business use of public power transmission facilities is disregarded in determining whether a prohibited change in use has occurred. The first of these provides that the use of public power transmission facilities pursuant to contracts entered into in response to wheeling required (or expected to be required) under sections 211 or 212 of the Federal Power Act or comparable State laws is not treated as a post-issuance deliberate action violating the private business tests (Temp. Treas. reg. sec. 1.141-7T(f)(5)(i)). This regulatory exception mirrors a separate, statutory provision in Code section 142(f)(2). The statutory provision, enacted as part of the Energy Policy Act of 1992 (P.L. 102-486), applies only to private activity tax-exempt bonds for the local furnishing of electricity. The second exception for transmission facility bonds provides that other actions taken by public power entities to implement non-discriminatory, open-access plans of FERC or a State are not treated as deliberate actions in determining whether the private business tests are violated with regard to outstanding tax-exempt bonds (Temp. Treas. reg. sec. 1.141-7T(f)(5)(ii)). There is no requirement in the second exception that the action be taken in response to or in anticipation of a requirement by the Federal Government or a State government.

In addition to preserving tax-exemption for previously issued public power transmission bonds under the circumstances described, the 1998 Temporary Regulations permit public power to refund that debt with new bonds, notwithstanding violation of the general tax-exempt bond rule that tax-exempt refunding bonds may only be issued if the private business tests (and all other requirements for tax-exemption) are not violated on the date the refunding occurs (Temp. Treas. reg. sec. 1.141-7T(f)(5)(iii)).

Finally, the 1998 Temporary Regulations provide that a “requirements” contract may violate the private business tests if the contract substantively results in private business use in excess of that allowed under the Code (Temp. Treas. reg. sec. 1.141-7T(c)(4)). A requirements contract is a contract under which the purchaser agrees to purchase all or a portion of its requirements from the seller. The regulations provide three primary factors that are to be used to establish whether requirements contracts violate the private business tests.

Issuance of tax-exempt bonds for private activities

As stated above, interest on State or local government bonds to finance activities of private persons (both business and personal activities) is taxable unless a specific exception is contained in the Code (or in non-Code provision of a revenue Act). The Code includes exceptions permitting States or local governments to act as conduits providing tax-exempt financing for certain private activities. In most cases, the aggregate volume of these tax-exempt private activity bonds is restricted by annual aggregate volume limits imposed on bonds issued by issuers within each State. The Code further imposes several additional restrictions on tax-exempt private activity bonds that do not apply to bonds for governmental activities.

Eligible activities

In general.--States or local governments may issue tax-exempt exempt-facility bonds to finance facilities for certain private businesses. Business uses eligible for this financing generally include transportation (airports, ports, local mass commuting, and high speed intercity rail facilities); privately owned and/or privately operated public works facilities (sewage, solid waste disposal, local district heating or cooling, and hazardous waste disposal facilities); privately-owned and/or operated low-income rental housing; and, certain private facilities for the local furnishing of electricity or gas. A further provision allows tax-exempt financing for "environmental enhancements of hydro-electric generating facilities." This provision was enacted to permit tax-exempt financing of certain renovations to the dams and accompanying hydroelectric electric generating facilities along the Columbia River that are a part of the Bonneville Power Administration system.[16]

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[16] Two additional non-Code provisions allow tax-exempt financing for certain electric generating facilities located in the State of Alaska. The first of these treats the Bradley Lake hydro-electric generating plant as a facility for the local furnishing of electricity. The second authorized issue of tax-exempt private activity bonds to finance the sale by the Federal Government of the Snettisham electric generating facility, also in Alaska, without satisfaction of the general rehabilitation requirement applicable to private activity bonds, because after the sale the facility's output was to be sold to an IOU in Juneau, Alaska.

Tax-exempt financing is authorized for capital expenditures for certain manufacturing facilities and land and equipment for first-time farmers ("qualified small-issue bonds"), certain local redevelopment activities ("qualified redevelopment bonds"), and eligible empowerment zone and enterprise community businesses.[17] Further, certain non-business private purposes may be financed with proceeds of these bonds: certain student loans, mortgage loans for first-time home buyers satisfying moderate income and home purchase price requirements, and mortgage loans generally for certain pre-1977 veterans who purchase homes in any of the five States that historically authorized issuance of these bonds.[18] [19] Finally, both capital expenditures and limited working capital expenditures of charitable organizations described in section 501(c)(3) of the Code may be financed with tax-exempt bonds ("qualified 501(c)(3) bonds").

Private activity bonds for the local furnishing of electricity.–Tax-exempt private activity bonds may be issued by States or local governments acting as conduits to finance generation, transmission, and distribution facilities for private businesses engaged in the local furnishing of electricity ("local furnishers"). A business is treated as engaged in local furnishing of electricity if the service territory in which the electricity is provided does not exceed (1) two contiguous counties, or (2) a city and a contiguous county. Historically, local furnishers eligible for this tax-exempt financing have included both IOUs and independent power ventures. These bonds may be issued for the benefit of only those persons that were engaged in local furnishing of electricity in the service territory in which the new facilities will be used as of January 1, 1997, or in qualified expansions of those service territories. A "qualified expansion" is limited to service territory that is a part of a county in which the local furnisher was providing electric service on that date. For example, if a local furnisher was providing electric service to one county and a portion of a contiguous county on January 1, 1997, bonds may be issued for the continued provision of service both within that area and also for service to be provided in the remaining portion of the contiguous county in the future. In addition to persons actually engaged in local furnishing activities on January 1, 1997, the Code allows certain successors in interest to persons that qualified as local furnishers on that date to "step into the shoes" of the predecessor local furnishers provided that the service territories served otherwise satisfy the requirements for local furnishing.

Notwithstanding the general limits on service territories of local furnishers, the Code includes special rules allowing these electric service providers to transmit ("wheel") electricity

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[17] A separate non-Code exception allows the State of Iowa to issue tax-exempt private activity bonds to finance an industrial new jobs program.

[18] The five States are Alaska, California, Oregon, Texas, and Wisconsin.

[19] A non-Code exception allows the State of Texas to issue tax-exempt private activity bonds to finance limited amounts of land for veterans (in addition to any veterans mortgage bonds that Texas may issue).

through their systems, if ordered by the Federal Energy Regulatory Commission to do so under sections 211 or 213 of the Federal Power Act, provided that the size of the transmission lines or other facilities used in these wheeling activities does not exceed the capacity required to serve their otherwise qualified two county or city and a county service area.

In general, if a local furnisher ceases to qualify as such, interest on outstanding tax-exempt bonds issued for its benefit becomes taxable, and interest payments by the local furnisher on loans securing the bonds becomes nondeductible. A special election allows local furnishers to avoid these penalties if the local furnishers do not benefit from any tax-exempt bonds issued after August 19, 1996. If that election is made, in lieu of loss of tax-exemption on outstanding bonds and loss of interest deductions on underlying loans, all outstanding bonds from which the local furnisher benefits must be redeemed no later than six months after the earliest date on which redemption is permitted under the bond covenants (or the date of the election, if later). This election must be made for all local furnishing facilities of the local furnisher rather than on a facility-by-facility or bond-issue by bond-issue basis.

Additional restrictions imposed on private activity tax-exempt bonds

State volume limitations.--Issuance of most tax-exempt private activity bonds is subject to an annual volume limitation that each State receives. This volume limit is equal to the greater of $50 per resident of the State, or $150 million. These dollar amounts are scheduled to increase to $75 per resident or $225 million, beginning in calendar year 2007. The increase is scheduled to be phased-in ratably beginning in calendar year 2003.

This limit also applies to the private business portion of certain larger governmental bond issues; such private business use in excess of $15 million (and up to the permitted 10 percent of the issue) must receive an allocation of State volume limitation for interest on the overall bond issue to be tax-exempt.[20] Exceptions to the volume limitation are provided for bonds to finance airports, ports, solid waste disposal facilities (if governmentally owned), qualified 501(c)(3) bonds, and high speed intercity rail facility bonds (if governmentally owned), and bonds for environmental enhancements of hydro-electric generating facilities. Additionally, bonds for privately owned high speed intercity rail facilities are required to receive a State volume limitation allocation only for 25 percent of the amount of the bonds.

Miscellaneous other restrictions.–Tax-exempt private activity bonds are subject to several other restrictions that do not apply to governmental bonds. These restrictions include the requirement of a public hearing and approval of their issuance by an appropriate elected

[20] Unlike this general provision for larger governmental bond issues, the $15 million limit on private business use of output facility bonds, described above, is an absolute limit which may not be waived by an allocation of State private activity bond volume limitation.

governmental official, a prohibition on advance refundings,[21] a restriction on the term to maturity of the bonds measured by reference to the economic lives of the property to be financed, minimum rehabilitation requirements for bonds used to finance acquisition of existing property, and, in general, slightly more restrictive limits on arbitrage profits that may be earned.[22]

Penalties for violation of tax-exempt bond restrictions after issuance

General change in use penalties and administrative alternatives

In general, the determination of whether interest on State or local government bonds is tax-exempt is made when the bonds are issued. That is, the determination is made by reference to how the bond proceeds are "to be used" (sec. 141). Intentional acts after the date of issuance to use bond-financed property (indirectly a use of bond proceeds) in a manner not qualifying for tax exemption may render interest on the bonds taxable, retroactive to the date of issuance (the "change in use rules"). Such a prohibited change in use may be illustrated by the subsequent sale of public power electric output to private businesses in a manner not qualifying for tax exemption after the bond-financed property is placed in service. Other privatization programs transferring the operation of State or local government programs to private businesses similarly can give rise to a prohibited change in use as can the sale or lease of bond-financed State or local government facilities to private businesses.

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[21] The prohibition does not apply to qualified 501(c)(3) bonds. Governmental bonds and qualified 501(c)(3) bonds may be advance refunded one time. An advance refunding occurs when the refunded bonds remain outstanding for a period greater than 90 days after issuance of the refunding bonds. Advance refundings typically are undertaken because an issuer includes provisions in its original bond documents agreeing not to redeem the bonds before expiration of a minimum period. Advance refundings are used to restructure debt service generally, to eliminate restrictive covenants contained in outstanding bond documents, or to hedge against anticipated future interest rate increases by locking in for the future what is believed to be a favorable rate. In an advance refunding both the refunded and the refunding bonds remain outstanding until the refunded bonds may be redeemed under their contractual terms. Proceeds of the refunding bonds are deposited in a yield-restricted escrow account until that time.

[22] The Code in general limits the amount of arbitrage profits may be earned on tax-exempt bonds and requires that most such profits be rebated to the Federal Government. These provisions are designed to preclude issuance of tax-exempt bonds earlier than necessary for the governmental or approved private activity which is the stated purpose of the borrowing or in larger amounts than required for the purpose. Absent such restrictions, State or local governments as tax-exempt entities could borrow at tax-exempt rates and invest in, for example, taxable Federal Government debt, as an income production undertaking. Such as undertaking would reduce Federal revenues by substituting tax-exempt debt for taxable debt in the hands of taxable bond investors.

In the 1997 Final Regulations and an accompanying Revenue Procedure,[23] the Treasury Department administratively provided alternative remedies to loss of tax-exemption for certain changes in use of governmental bonds. The alternative remedies are available only if five conditions are satisfied:

> (1) The issuer of the bonds must have reasonably expected on the date of the borrowing that the bonds would not meet the private business and private loan tests for their entire term;[24]
>
> (2) The term of the bonds must not be longer than is reasonably necessary for the governmental purposes of the borrowing;
>
> (3) The change in use must result from a bona fide, arm's length transaction for fair market value;[25]
>
> (4) Any disposition proceeds must be treated as "gross proceeds" of the bond issue, subject to the Code arbitrage rules; and
>
> (5) The bond proceeds must have been spent for the purpose of the borrowing before the change in use occurs (unless the bonds are redeemed) (Treas. reg. sec. 1.141-12(a)).

If the five conditions are satisfied, four possible alternative remedies to loss of tax-exemption are available for post-bond-issuance actions violating the private business tests. First, all currently callable bonds may be redeemed within 90 days after the change in use and all other bonds may be defeased with a yield-restricted escrow and called on the first date when that

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[23] Revenue Procedure 97-15, 1997-1 C.B. 635.

[24] Absent satisfaction of this reasonable expectations test, bonds are eligible for the alternative remedies only if the issuer (1) on the issue date the issuer reasonably expected to use the bond-financed property in a qualified use for a substantial period, (2) redeems *all* nonqualified bonds within six months of any action changing that use to a nonqualified one, (3) has no arrangement with a private business as of the issue date regarding a nonqualified change in use, and (4) otherwise meets the regulatory remedial actions. The requirement that all nonqualified bonds be redeemed includes redemption in cases where bond-financed property is disposed of for less than the unpaid bond amount. In such cases, the issuer must make up any shortfall in the disposition proceeds from other sources to avoid bond interest being rendered taxable.

[25] The determination of fair market value may take into account restrictions on the use of the bond-financed property that serve "a bona fide government purpose."

action is permitted under the bond terms (Treas. reg. sec. 1.141-12(d)).[26] Second, in the case of dispositions entirely for cash where the bond issuer expects to spend the disposition proceeds within two years after the change in use, the disposition proceeds may be treated as bond proceeds and used accordingly, subject to all of the Code's tax-exempt bond provisions (Treas. reg. sec. 1.141-12(e)). To the extent the disposition proceeds are not used for a qualifying use within the two-year period, bonds must be redeemed.

A third remedy provides that loss of tax-exemption will not occur if bond-financed property is transferred in a transaction constituting a change in use from a governmental use to a use that is eligible for financing with tax-exempt private activity bonds provided that the issuer treats the bonds as reissued on the date the change in use occurs and satisfies rules applicable to the revised use of the bonds (including where applicable, allocation of State private activity bond volume limitation) (Treas. reg. sec. 1.141-12((f)).[27] The final alternative remedy to loss of tax-exemption allows the issuer to pay the Federal Government an amount equal to lost tax revenues from allowing nonqualified tax-exempt bonds to remain outstanding as tax-exempt (Rev. Proc. 97-15, *supra*.)

Additional change in use penalties for private activity tax-exempt bonds

In addition to loss of tax-exemption on bond interest, conduit borrowers receiving tax-exempt private activity bond financing lose interest deductions on their underlying loans if the use of the bond-financed property changes to a non-qualified use after issuance (the "additional change-in-use rules"). For example, if the output of an IOU facility for the local furnishing of electric service is used to provide service beyond the permitted two county or city and a county area, interest paid by the IOU on loans underlying the tax-exempt bonds is nondeductible (sec. 150(b)).[28]

2. Examples of Private Business Use Issues Arising in Electric Power Industry

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[26] The maximum period of the escrow account may not exceed 10-1/2 years.

[27] Because the original tax-exempt bonds remain outstanding, a purchaser of property financed with tax-exempt bonds qualifying for this remedy is not permitted to finance any acquisition costs with additional tax-exempt bonds (e.g., tax-exempt exempt-facility bonds could not be issued to finance the transfer of a governmental solid waste disposal system to a private business).

[28] An exception to this rule, enacted in 1996 and described above, provided that this penalty and loss of tax-exemption on bonds not apply to bonds issued before August 20, 1996, in the case of service territory expansions by local furnishers of electricity or gas that elect to forego additional tax-exempt financing from bonds issued after August 19, 1996, and satisfy certain other conditions.

Restructuring

"Open access" proposals for restructuring the electric power industry assume greater integration of facilities of the participating electric service providers. Under these proposals, electric service providers are expected to compete for customers, both within their current service territories and within areas currently served by other providers as well. To foster this competition, providers may be required to transmit or distribute ("wheel") electricity over their facilities to customers of other providers. Additionally, certain plans have called for public power, IOUs, and co-ops to surrender at least some of their facilities (notably transmission lines) to third party control. Each of these circumstances may limit the ability of public power entities and local furnishers of electricity to finance future facilities with tax-exempt bonds, and may render interest on outstanding bonds retroactively taxable unless the issuers qualify for and avail themselves of certain administrative relief provided in Treasury Department regulations. The following examples illustrate arrangements which could affect tax-exempt status of outstanding bonds or the ability of public power entities and local furnishers of electricity to issue new tax-exempt debt if those providers participate in open access plans.

Example (1).--Assume that XYZ Manufacturing Company is located in the service territory of Public Power Agency A which traditionally has supplied electricity to the company. A has elected to participate in the open access plan of the state where A is located. Independent Power Producer B offers to supply the electricity requirements of XYZ at rates set under contract and which are lower than those offered by A to its other customers. XYZ uses 5 percent of the electricity supplied by A, but that electricity comprises more than $15 million of the output of A's electric facilities. A enters into a long-term contract with XYZ which matches the prices offered by B and does not offer the same rates as generally available to its other customers. Assume further that the payments under the contract are equal to the amount of private business use involved. A has taken a deliberate action causing its bonds to violate the Code private business tests. Unless A qualifies for (1) one of the general remedial actions for correcting prohibited changes in use of tax-exempt-bond-financed property prescribed in Treasury Department regulations or (2) temporary relief provided under the 1998 Temporary Regulations, interest on A’s bonds would become taxable retroactive to the date of their issuance.

Example (2).--Under facts similar to those of Example (1), neighboring IOU C contracts with Big Box Retailer in Public Power Agency A's service territory. As a result, A has surplus electricity generating capacity exceeding 10 percent of its generating capacity. A wants to sell that capacity to Electricity Broker D for re-sell pursuant to a firm price long-term contract having different rates than A's tariff prices to its regular customers. Assume further that the contract price would exceed 10 percent of the debt service on A's bonds. The firm price contract between A and D would be treated as a deliberate action giving rise to private business use under the Code tax-exempt bond rules. Interest on A's outstanding bonds would become retroactively taxable unless A qualified for one of the general remedial actions for correcting prohibited changes in use of tax-exempt bond-financed property or temporary relief provided under the 1998 Temporary Treasury Regulations (*e.g.*, in sec. 1.141-7T(f)(4)).

Example (3).--Under the facts of Example (2), A decides that it prudently must improve its generating plant. A may not issue tax-exempt bonds to finance the improvements because an amount exceeding the lesser of 10 percent or $15 million of the output of the facility is used in a private business use and a like amount of the debt service on its bonds is secured by such payments. Except as provided in Temp. Treas. reg. sec. 1.141-7T(f)(4), the result in this example is identical whether the additional debt would be used to finance repairs and maintenance activities or improvements to the facility.

Example (4).--As part of its agreement to participate in State E's open access plan, Public Power Agency F must agree to allow Investor-Owned Utilities G and H to use its transmission and distribution facilities. G and H use those facilities to provide electric service to F's former customers T Manufacturing Company and Big Box Retailer that have elected to purchase electricity from G and H under a firm price contract. G and H's use of the facilities (and the payments therefore) exceed $15 million and occurs under fixed contractual terms that enable G and H to enter the fixed price contract with F's former customers. Assume that F makes no offsetting use of G or H's transmission and distribution facilities. When F permits G and H to use its transmission facilities, it has taken a deliberate action that violates the Code's private business use and payment limits. Interest on its bonds will become retroactively taxable unless F qualifies for and satisfies one of the general remedial actions prescribed in Treasury Department regulations or the provisions of Temp. Treas. reg. sec. 1.141-7T(f).

Example (5).--Under State I's open access plan, control of all transmission facilities (including public power, IOU, and co-op facilities) would be transferred to an independent system operator ("ISO"). ISO is an agency of State I and qualifies as a State government unit under the Code's tax-exempt bond rules. ISO would operate all of the transmission lines within State I as a single system without regard to whether electricity transmitted over any given facilities constituted private business use. Public Power Agency A financed its transmission facilities with tax-exempt bonds. If A elects to participate in the open access plan and I uses A's transmission facilities in a manner violating the Code private business tests, interest on A's bonds would become retroactively taxable unless A is eligible for and satisfies one of the general remedial actions prescribed in Treasury Department regulations. (If on the other hand, ISO was a private entity rather than a unit of State government, the private business test would be violated when control of the transmission lines was transferred, and interest on I's bonds would become retroactively taxable except to the extent provided in Temp. Treas. reg. sec. 1.141-7T(f)(5)).

Example (6).--Under facts similar to those of Example (4), Local Furnisher J allows other investor-owned electric service providers to use its transmission and distribution facilities. Assume further that the use is not pursuant to a FERC order or the other circumstances described in Code section 142(f)(2). Interest on J's bonds financing these facilities will become retroactively taxable (and interest deductions on loans to J underlying the bonds will be disallowed prospectively) unless J qualifies for and makes the special election of Code section 142(f)(3) terminating its status as a local furnisher.

Example (7).--Under facts similar to those of Example (2), Local Furnisher K has excess capacity which it wishes to sell to customers located outside local furnishing service area. The provision of service to customers located outside of a qualified local furnishing service area will render interest on K's bonds retroactively taxable (and K's interest payments on loans underlying the bonds prospectively nondeductible) unless K qualifies for and makes the special election of Code section 142(f)(3) terminating its status as a local furnisher.

B. Additional Tax Provisions Affecting Investor-Owned Utilities

1. Cost Recovery of Property Used in the Production, Transmission, and Distribution of Electricity

a. Present and prior law

Tax depreciation generally

A taxpayer generally must capitalize the cost of property used in a trade or business and is allowed to recover such cost over time through allowances for depreciation or amortization. Code section 167 allows annual depreciation deductions for the reasonable allowance for the exhaustion, wear and tear, or obsolescence of the capitalized cost of property. Theoretically, the exhaustion, wear and tear, or obsolescence of depreciable property would be most accurately determined by "economic depreciation." Under economic depreciation, property is valued and "marked-to market" on an annual basis and any decrease in value from one year to the next is allowed as a depreciation deduction. Economic depreciation generally is conceded to be difficult to administer due to the case-by-case, annual valuations of each property that would be required.

Prior to 1981, taxpayers were allowed to depreciate the cost of property (net of salvage value) over the useful life of the property (i.e., the period over which the property is reasonably expected to be useful to the taxpayer in its trade or business). This depreciation method, known as "facts and circumstances" depreciation, allows the taxpayer to estimate (and re-estimate) the useful life and salvage value of property, often resulting in disputes between taxpayers and the Internal Revenue Service ("IRS"). Under facts and circumstances depreciation, reasonable allowances for depreciation could be computed using a straight-line or an accelerated method (such as a declining balance method or a sum of the years-digits method).

In order to minimize some of these controversies, the IRS published depreciation guidelines in 1962.[29] These guidelines assigned useful lives to a few common types of assets, and grouped other assets based on the activity in which they were used. The useful lives provided by these guidelines formed the basis of the asset depreciation range ("ADR") system that could be elected by taxpayers for property placed in service after 1970 and before 1981.

Facts and circumstances depreciation was repealed by the enactment of the Accelerated Cost Recovery System ("ACRS") in 1981. For property placed in service after 1980 and before 1987, ACRS generally provides that depreciation is computed by applying specific recovery allowances over specified periods for various types of depreciable property. ACRS provided accelerated methods and 10- and 15-year recovery periods for "public utility property;" most other tangible personal property had a 5-year recovery period. Depreciation under ACRS generally

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[29] Rev. Proc. 62-21, 1962-2 C.B. 418.

recovered the cost more quickly than under either economic or facts and circumstances depreciation.

For property placed in service after 1986, depreciation allowances for tangible property generally are determined under the modified Accelerated Cost Recovery System ("MACRS") of Code section 168. MACRS is similar to ACRS, but generally provides less generous depreciation allowances.[30] Under MACRS, property is assigned a recovery period that generally is based on the class life of the property under the asset depreciation range ("ADR") system in effect before 1981. The MACRS recovery periods range from 3 to 50 years. The recovery periods for some types of property (such as alternative energy and biomass property described in the Table 1 below) are prescribed by statute. The depreciation method generally applicable to property with a recovery period of less than 15 years is the 200-percent declining balance method (switching to the straight-line method in the year that maximizes the depreciation deduction). The 150-percent declining balance method (switching to the straight-line method in the year that maximizes the depreciation deduction) applies to property with recovery periods of 15 or 20 years, and the straight-line method applies to property with a recovery period over 20 years (generally, real property). In addition, MACRS removed the distinction between public utility property and any other property used to provide similar services. Despite being less generous than ACRS, it is generally believed that MACRS often recovers the cost of property faster than under either economic or facts and circumstances depreciation.

The MACRS recovery periods and depreciation methods for property used in the production, transmission, and distribution of electricity are described in Table 1 below.[31]

[30] The depreciation deductions computed under section 168 for regular tax purposes may be adjusted under the alternative minimum tax ("AMT"). The AMT generally is a separate system that imposes tax at a lower rate upon a broader base of income than does the regular tax. For property placed in service after December 31, 1998, AMT depreciation deductions are to be computed using the recovery periods prescribed by section 168 and the 150-percent declining balance method (or the straight-line method for property subject to such method for regular tax purposes). For property placed in service before January 1, 1999, AMT depreciation deductions generally are computed using recovery periods longer than those prescribed for regular tax.

[31] Rev. Proc. 87-56, 1987-2 C.B. 674.

Table 1.--Recovery Periods and Depreciation Methods Applicable to Electric Utility Property Under MACRS

Asset Class	Description of asset	Recovery period (years)	Depreciation method
49.11	Electric Utility Hydraulic Production Plant (includes assets used in hydraulic power production of electricity for sale, including related land improvements, used as dams, flumes, canals and waterways)	20	150% declining balance
49.12	Electric Utility Nuclear Production Plant (includes assets used in nuclear pows production and electricity for sale and related land improvements; does not include nuclear fuel assemblies)	15	150% declining balance
49.121	Electric Utility Nuclear Fuel Assemblies(includes initial core and replacement core nuclear fuel assemblies (i.e., the composites of fabricated nuclear fuel and container) when used in boiling water, pressurized water, or high temperature gas reactor used in the production of electricity; does not include nuclear fuel assemblies used in breeder reactors)	5	200% declining balance

Asset Class	Description of asset	Recovery period (years)	Depreciation method
49.13	Electric Utility Steam Production Plant (includes assets used in the steam power production of electricity for sale, combustion turbines operated in a combined cycle, with a conventional steam unit and related land improvements; also includes package boilers, electric generators and related assets such as electricity and steam distribution systems as used by a waste reduction and resource recovery plant if the steam or electricity is normally for sale to others)	20	150% declining balance
49.14	Electric Utility Transmission and Distribution Plant (includes assets used in the transmission and distribution of electricity for sale and related land improvements; generally excludes clearing initial grading land improvements)	20	150% declining balance
49.15	Electric Utility Combustion Turbine Production Plant (includes assets used in the production of electricity for sale by the use of such prime movers as jet engines, combustion turbines, diesel engines, gasoline engines, and other internal combustion engines, their associated power turbines, and/or generators, and related land improvements; does not include combustion engines operated in a combined cycle with a conventional steam unit)	15	150% declining balance

Asset Class	Description of asset	Recovery period (years)	Depreciation method
----	Alternative Energy Property (sec. 168(e)(3)(B)(vi)(I) and (III)) (generally, equipment that uses solar or wind energy to generate electricity; equipment used to produce, distribute, or use energy derived from a geothermal deposit up to the point of the electrical distribution stage; or equipment that converts ocean thermal energy into usable energy at one of two locations designated by the Secretary Treasury)	5	200% declining balance
----	Biomass Property (sec. 168(e)(3)(B)(vi)(II)) (assets described in section 48(l)(15) (as in effect on November 5, 1990), and is a qualifying small production facility within the meaning of section 3(17)(c) of the Federal Power Act, (16 U.S. C. 796(17)(C) (as in effect on September 1, 1986))	5	200% declining balance

In addition, under present law, a taxpayer may elect to amortize (over 60 months) the amortizable basis of any certified pollution control facility (sec. 169). A certified pollution control facility is a facility (1) to abate or control water or air pollution, (2) that is State- or Federally-certified for such purposes, (3) that is used in connection with a plant or other property placed in service before 1976, and (4) that does not extend the useful life, reduce the operating cost, or alter the manufacturing or production process of the plant or other property. The amortizable basis is the cost of such facility. However, if the facility has a useful life greater than 15 years, the amount amortizable over 60 months is equal to the cost of the property multiplied by a fraction equal to 15 divided by the useful life. Any cost not amortizable under section 169 may be depreciated as tangible property under sections 167 and 168.

Pollution control facilities often are placed in service with respect to public utility property (e.g., coal scrubbers used in connection with coal-fired electric generating facilities). Such property generally have useful lives greater than 15 years. Thus, under present law, only a portion of the cost of such facilities may be amortized over 60 months, with the remainder determined under MACRS (generally, using the 150-percent declining balance method over 15 or 20 years).

b. Normalization of tax benefits derived from accelerated tax depreciation

In order for public utility property to be eligible for the more favorable depreciation allowances available for tax purposes (relative to the depreciation allowances used for ratemaking or financial statement purposes), the tax benefits of accelerated depreciation must be normalized in setting rates charged by utilities to customers and in reflecting operating results in regulated books of account.[32]

Under present law, the tax benefits of accelerated depreciation are considered to be normalized only if three requirements are satisfied (sec. 168(i)(9)(A)). First, the tax expense of the public utility for ratemaking purposes must be computed by using the same depreciation method that is used in determining depreciation for ratemaking purposes and by using a useful life that is no shorter than the useful life used in determining depreciation for ratemaking purposes (which generally results in depreciation being determined over a relatively long useful life and using the straight-line method). Second, the difference between the actual tax expense computed using tax depreciation and the tax expense determined for ratemaking purposes must be reflected in a deferred tax reserve. Third, in determining the rate of return of a public utility, the public utility commission may not exclude from the rate base an amount that exceeds the addition to the deferred tax reserve for the period used in determining the tax expense for ratemaking purposes. In addition, any ratemaking procedure or adjustment with respect to a utility's tax expense, depreciation expense, or reserve for deferred taxes must also be consistently used with respect to the other two items and rate base (sec. 168(i)(9)(B)).

Any violation of these requirements results in the loss of the application of accelerated tax depreciation for the applicable public utility property and the depreciation allowances for such property must be determined for Federal income tax purposes under the method used for regulatory purposes (secs. 168(f)(2) and (i)(9)(C)). Under present law, public utility property is defined as property used predominantly in the trade or business of the furnishing or sale of: (1) electrical energy, water, or sewage disposal services; (2) gas or steam through a local distribution system; (3) telephone services; (4) other communications services if furnished or sold by the Communications Satellite Corporation for purposes authorized by the Communications Satellite Act of 1962 (47 U.S.C. 701); or (5) transportation of gas or steam by pipeline, if the rates for such furnishing or sale are established or approved by a State or political subdivision thereof, by any agency or instrumentality of the United States, or by a public service or public utility commission or other similar body of a State or political subdivision thereof (sec. 168(i)(10)).

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[32] Similar rules are provided for certain public utility property placed in service prior to 1986 (the first year that MACRS was applicable).

Example of normalization method of accounting

In order to understand the effect of the Federal income tax normalization requirement on the determination of rates charged for utility services, an understanding of the ratemaking process and an alternative method of accounting for accelerated tax depreciation benefits (the "flow-through" method) is helpful.

The ratemaking process–in general

The ratemaking process is a means by which the revenue requirements of a utility are determined. In setting utility rates, public utility commissions generally attempt to allow the utility to collect enough charges from utility customers to (1) recover operating expenses (the cost of service element), and (2) provide a fair rate of return to investors (the rate of return element). Expenses taken into account in determining the cost of service element include labor, fuel, materials, depreciation on utility plant and equipment, and income tax expense. The rate of return element typically is computed by multiplying (1) an allowable rate of return (as determined by the public utility commission) times (2) the rate base. The allowable rate of return is generally determined with reference to the utility's weighted cost of borrowing plus an appropriate return on equity capital. Rate base is usually computed as the working capital of the utility, plus the original cost of utility plant and equipment, less accumulated regulatory depreciation, and less the deferred tax reserve (as described below). The deferred tax reserve is deducted from rate base for purposes of computing the rate of return element because the reserve is considered to be a no-cost source of capital. Thus, Federal income taxes are an important factor in determining the rates a utility may charge its customer because (1) income tax expense is considered a recoverable cost of service, and (2) deferred income taxes reduce the rate base upon which an allowable rate of return is applied.

Methods of accounting for tax depreciation: flow-through vs. normalization

Flow-through accounting.--The determination of the amount of Federal income taxes reflected in cost of service and rate base depends on the treatment of depreciation of utility property. The use of an accelerated depreciation method for Federal income tax purposes results in an actual Federal income tax liability that differs from the Federal income tax liability that would have been incurred if the typically slower depreciation methods used for regulatory purposes had been used for tax purposes. In general, in the first few years after property has been placed in service, the Federal income tax liability will be lower than if the regulatory depreciation schedule had been used. The Federal income tax liability will be greater in later years when the tax depreciation allowances are less than the regulatory depreciation allowances.

Flow-through accounting treats the actual Federal income tax liability of the regulated utility as reported on its tax return as the utility's tax expense in determining appropriate utility rates. Under flow-through accounting, the tax benefits of accelerated depreciation are taken into account as they are claimed in determining utility rates. Thus, under flow-through accounting, utility rates are lower for those consumers who are charged for service in the earlier years of the useful live of the utility property (relative to those consumers who are charged for service in later years).

Normalization accounting.--In contrast, under normalization accounting, the utility's tax expense for ratemaking purposes is determined by using regulatory depreciation allowances. The use of regulatory depreciation allowances generally results in the spreading of the tax benefits of accelerated tax depreciation over the regulatory life of the property. The normalization method for accelerated depreciation requires adjustments to actual Federal income tax liability to arrive at the regulatory tax expense and adjustments to rate base. The accumulation of the differences between regulatory tax expense and actual Federal tax liability creates a deferred tax reserve that represents both accumulated Federal income tax savings and expected future Federal tax liabilities. Normalization accounting is consistent with generally accepted accounting principles used to prepare financial accounting statements.

Example 1.--Assume a calendar year regulated utility placed property costing $100 million in service in 1997. For regulatory (book) purposes, the property is depreciated over 10 years on a straight-line basis with a full year's allowance in the first year. For tax purposes, the property is 5-year property and is recovered using the straight-line method, with a full year's deduction allowed in 1997.[33] Assuming a tax rate of 35 percent for all years, deferred taxes (the tax rate times the difference between tax and book depreciation) would be computed as shown in Table 2.

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[33] The 5-year tax and 10-year book lives, the straight-line tax method and the full depreciation allowance for the first year are used for illustration purposes only. In general, public utility property is 5-, 15-, or 20-year property under MACRS, is depreciated using an accelerated depreciation method, and is subject to a mid-year placed-in service convention. for regulatory purposes, public utility property may have a life of 30 years or more.

Table 2.--Deferred Tax Reserve Assuming Constant Tax Rates
(Millions of Dollars)

	1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003-06**	**1997-06**
Tax depreciation	20	20	20	20	20	0	0	100
Book depreciation	10	10	10	10	10	10	40	100
Timing Difference	10	10	10	10	10	[10]	[40]	----
Tax Rate	.35	.35	.35	.35	.35	.35	.35	----
Annual adjustments to reserve	3.5	3.5	3.5	3.5	3.5	[3.5]	[14.0][1]	----
Deferred tax reserve	3.5	7.0	10.5	14.0	17.5	14.0	----	----

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1 The deferred tax reserve is reduced by $3.5 million a year for 2003 through 2006 so that no reserve exists as of December 31, 2006.

Under flow-through accounting, Federal tax expense is determined with reference to accelerated tax depreciation and no deferred tax reserve is created. Under normalization accounting, Federal tax expense is determined with reference to book depreciation and a deferred tax reserve is created to account for the accumulated tax benefits arising from the differences between tax and book depreciation. In Table 2, above, the use of accelerated tax depreciation in the first five years of the property's life results in a deferred tax reserve of $17.5 million at the end of 2001 which, under normalization accounting, is then reduced over the remaining regulatory life of the property.

Generally, if normalization accounting is followed in the ratemaking process, the $17.5 million deferred tax reserve at December 31, 2001, would have been included as a portion of income tax expense in computing cost of service for years 1997 through 2001. The $17.5 million deferred tax reserve generally would have also reduced the rate base over that same period. In that case, rate base with respect to this property, as of December 31, 2001, would be $32.5 million ($100 million original cost, less $50 million accumulated book depreciation, less the $17.5 million deferred tax reserve).

Normalization accounting methods adjust for various timing differences between tax and regulatory accounting of utilities. The benefit of the interest-free loan created by accelerated cost recovery for tax purposes could be distributed to consumers in a variety of ways. However, normalization as applied to accelerated depreciation for Federal income tax purposes attempts to distribute to consumers the benefit of the interest-free loan made to the utility over the entire useful life of the asset. Because accelerated tax benefits are front-end loaded, utility rates under the normalization method are higher in the early years of the life of the property than the rates would be under the flow-through method. However, as these tax benefits reverse (i.e., as ratemaking depreciation exceeds tax depreciation), utility rates under the normalization method become lower than the rates computed under the flow-through method. Theoretically, because the normalization method results in decreases to a utility's rate base that are not present under the flow-through method, the present value of utility rates over the life of the property under the normalization and flow-through methods should be equal, when discounted at the rate of return that is applied to rate base for ratemaking purposes.

It has been argued that a purpose of normalization is to ensure that the capital subsidy of accelerated tax depreciation provides an investment incentive for regulated utilities. Some reason that if tax benefits were flowed through to ratepayers immediately, the utility would have no incentive to invest in property to which such benefits accrue. Proponents of normalization accounting claim that even if the normalization and flow-through methods theoretically should equalize rates over time on a present-value basis, practical aspects of the ratemaking process may distort such results.

c. Tax issues raised by electric utility restructuring

Treatment of stranded costs

Regulated public utilities have traditionally provided generation, transmission, distribution, and retailing services to the ratepayers in their service territories on a monopolistic basis. The rates charged by electric utilities for these services are regulated by public utility commissions based on the premise that, absent such regulation, utilities may take advantage of their position as sole providers of utility services to earn excessive profits at the expense of consumers. One of the goals of the proposals to restructure the electric utility industry is to eliminate this rate regulation and to introduce competition in the provision of generation and perhaps in transmission and retailing services.

Rate regulation typically guaranteed the recovery of both the amount invested in property to be used in the business, as well as an sufficient return on the investment. So long as this guarantee existed, electric utilities were able to invest in property without regard to the fair market value of such property in a unregulated environment, or the amount of income such property could earn if used to produce power for sale at competitive rates. In certain instances, utilities, with the knowledge of the appropriate regulatory body, may have invested in property whose cost could only be justified by the presence of a guaranteed return.[34]

The proposed restructuring of the electric power industry could affect the value of property that was placed in service in a regulated environment. If the return on the investment in the property is no longer guaranteed through rate regulation, the value of the property will be determined solely by the amount of income the property can earn producing power at competitive rates. It is anticipated that competition will reduce the rates consumers pay for electric services, and thereby reduce the amount of income the property can earn producing power. Such a reduction in the rates for electric services could be expected to decrease the value of the existing assets used to produce such services.[35]

The extent to which the book or regulatory value of electric utility property exceeds its fair market value after restructuring is sometimes referred to as a "stranded cost." These costs are considered "stranded" because the electric service provider had anticipated recovering the full cost of the property under the ratemaking process when the property was placed in service and such recovery is unlikely in an unregulated environment. Proposals to restructure the electric power industry often address the issue of how to allow a utility to recover its stranded costs. Frequently, some or all of the stranded costs are allowed to be recovered through rates during a transition period.

Because of the accelerated depreciation allowances, the adjusted tax basis of electric utility property generally is lower than its book or regulatory value. In some instances, the fair market value of this property after deregulation may equal or exceed its adjusted tax basis, resulting in no "stranded costs" for tax purposes. However, in other instances, the adjusted tax basis of property will exceed its fair market value after the deregulation of the industry resulting in “stranded costs” for tax as well as book purposes.

There are no special tax provisions that allow for the immediate recovery of stranded costs. In order to recover the adjusted basis of depreciable property, the taxpayer generally must dispose of the property, abandon it, or show its obsolescence. In the absence of such an event, electric service providers will continue to depreciate the property in the same manner after the

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[34] A regulated utility may have been obligated to provide electricity to its customers on demand. To meet this obligation, the utility’s generating capacity (either owned or contracted) would be based on maximum projected demand, which may exceed the capacity the utility would have determined to be optimal in an unregulated environment.

[35] On the other hand, the value of underutilized assets that are already outside the regulatory environment could be increased by the proposed restructuring of the electric power industry, because the market for their output would be increased

restructuring of the industry as before the restructuring and will recover any stranded cost over the remaining depreciable life of the property.

Length of capital recovery period

Property placed in service by a public utility after 1980 and before 1987 generally is subject to ACRS, which provided 10- and 15-year recovery periods for "public utility property" (as defined in former Code section 167(l)). To the extent that such property is no longer subject to rate regulation under the restructuring of the industry, it would appear that such property would no longer be considered to be public utility property subject to the 10- and 15- year recovery periods, and instead may be classified as 5-year ACRS property. Proposed Treasury regulation 1.168-2(j)(3) provides that if the use of ACRS property changes, and such change in use results in the property having a shorter recovery period, the taxpayer may treat the lesser of (1) the adjusted basis or (2) the fair market value of the property as placed in service in the year of the change and subject to the shorter cost recovery schedule. It is unclear whether the proposed regulation applies in this case. In the event it does, restructuring may provide utilities with a limited opportunity to recover the basis of ACRS property faster. The opportunity is limited because the remaining recovery periods for most ACRS property is not significantly longer than five years.[36] This issue does not arise with respect to MACRS property because MACRS does not provide recovery periods that are specific to public utility property.

Depreciation allowances for property subject to facts and circumstances depreciation,[37] may be adjusted to take into account changes in useful life or salvage value. However, demonstrations of decreases in earning power or increases in competition often are insufficient to justify shortening the useful life or decreasing the salvage value of property, particularly where the taxpayer continues to use the property in the same manner.[38]

Effect on the normalization method of accounting

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[36] The opportunity is greater for property to which the ACRS transition rules of the Tax Reform Act of 1986 apply.

[37] Facts and circumstances depreciation applies to property placed in service before 1981. Public utilities may still have a significant amount of such property given the relatively long useful life of public utility property.

[38] See, Treas. reg. secs. 1.167(a)-1(c) (relating to salvage value), 1.167(a)-8 (relating to abandonment) and 1.167(a)-9 (relating to obsolescence). See, also, *Detroit and Windsor Ferryboat Co. v. Woodworth*, 115 F2d 795 (6th Cir 1940), *George Weidman Brewing Co. et al,* 9 BTA 792 (1927); *Farmers Feed Co. of NY,* 17 BTA 507 (1929) (relating to useful life and obsolescence).

The normalization method of accounting applies to public utility property subject to rate regulation. One of the goals of restructuring the electric power industry is to deregulate the generation, and in some cases the transmission, distribution, or retailing of electricity. Such restructuring raises several issues. First, as described above with respect to ACRS depreciation, the deregulation of the generation segment of the industry likely will cause the related property to no longer meet the definition of public utility property. If the entire utility is deregulated, the utility will not be subject to ratemaking processes and thus the normalization requirements will no longer apply.

If only a portion of an IOU's services are deregulated (e.g., the generation services, but not the distribution services) then a portion of the utility's property will remain public utility property subject to the normalization requirements and the remainder will not. In such instances, it appears that for purposes of the normalization requirements, the public utility commission with regulatory authority over the remaining regulated services cannot reduce rates for these services by any current or deferred tax benefits related to the deregulated property.[39] Such treatment raises certain policy issues. Opponents of this result note that the normalization method of accounting generally results in higher utility rates in the earlier years after the property was placed in service, relative to the flow-through method. Under this view, the existing deferred tax reserves represent excessive earlier rates that should be returned to the ratepayers.[40] Proponents of the normalization rulings claim that it would be unfair for ratepayers to receive any tax benefits for any property the cost for which the ratepayers are no longer responsible. Proponents also would

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[39] See, e.g., Private Letter Ruling ("PLR") 8920025, February 15, 1989, where the IRS ruled that where property is removed from a regulated use to a nonregulated use, the related deferred tax reserves also must be removed in order to meet the consistency rules of the normalization requirements. See, also PLR's 9613004, 9552007, 9547008, and 9312007 where the public utility commissions disallowed (i.e., denied recovery for) a portion of the cost of plant and equipment placed in service by public utilities. In these rulings the IRS held that the commissions could not reduce rates for any Federal income tax benefits related to the disallowed costs. Private letter rulings are only applicable to the taxpayer to whom issued and may not be used or cited as precedent. However, they are an indication of the IRS's ruling policy with respect to the normalization method of accounting.

[40] Proponents of flow-through accounting further would argue that such treatment is particularly appropriate for the "excess tax reserves" related to the deregulated property. The excess tax reserve is that portion of the reserve that was established prior the corporate income rate reduction provided by the Tax Reform Act of 1986 (which reduced the rate from 46 to 34 percent). Section 203(e) of the Tax Reform Act of 1986 provided that the excess tax reserves should be taken into account ratably over the remaining life of the utility's property. For a detailed discussion of section 203(e), see Joint Committee on Taxation, *Description of H.R. 1150 (The Utility Ratepayer Refund Act of 1987) and H.R. 2493 (The Utility Customer Refund Act of 1989)* (JCX-55-89), September 29, 1989.

point out that although the normalization method of accounting results in higher utility rates in the early years after the property is placed in service, the method results in lower rates in the later years, and that the deregulation of the electric utility industry should also provide such lower rates--giving ratepayers the same lower rates that they would have enjoyed under the normalization method.

The method by which the electric power industry is restructured may change the analysis above. If a public utility commission decides to transition IOUs into deregulation, the determination of whether or not certain property is public utility property subject to the normalization method of accounting may be difficult. For example, assume a State continues to regulate the rates charged to customers for the distribution of electricity, but to deregulate the rates applicable to electricity generation and transmission services. If in setting distribution rates, the State's public utility commission allows IOUs to recover a portion of the stranded costs applicable to generation or transmission property, it is unclear the extent to which such property is public utility property subject to the normalization method of accounting.

2. Other Tax Provisions of Industry Concern

a. Nuclear decommissioning

Present law

Special rules dealing with nuclear decommissioning reserve funds were adopted by Congress in the Deficit Reduction Act of 1984 (“1984 Act”), when tax issues regarding the time value of money were addressed generally. Under general tax accounting rules, a deduction for accrual basis taxpayers generally is deferred until there is economic performance for the item for which the deduction is claimed. However, the 1984 Act contains an exception to those rules under which a taxpayer responsible for nuclear power plant decommissioning may elect to deduct contributions made to a qualified nuclear decommissioning fund for future payment costs. Taxpayers who do not elect this provision are subject to the general rules in the 1984 Act.

A qualified nuclear decommissioning fund is a segregated fund established by the taxpayer that is used exclusively for the payment of decommissioning costs, taxes on fund income, and management costs of the fund, and for making investments. The qualified fund is prohibited from dealing with the taxpayer that established the fund. The income of the fund is taxed at a reduced rate of 20 percent for taxable years beginning after December 31, 1995.[41]

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[41] As originally enacted in 1984, the fund paid tax on its earnings at the top corporate rate and, as a result, there would be no present-value tax benefit of making deductible contributions to the fund. Also, as originally enacted, the funds in the trust could be invested only in certain low risk investments. Subsequent amendments to the provision have reduced the rate of tax on the fund to 20 percent and removed the restrictions on the types of permitted investments that the

Contributions to a qualified fund are deductible in the year made to the extent that these amounts were collected as part of the cost of service to ratepayers. Funds withdrawn by the taxpayer to pay for decommissioning expenses are included in the taxpayer's income and the taxpayer is entitled to a deduction for decommissioning expenses as economic performance of those costs occurs.

A taxpayer's contributions to the qualified fund may not exceed the amount of nuclear decommissioning costs included in the taxpayer's cost of service for ratemaking purposes for the taxable year. Additionally, in order to prevent accumulations of funds over the remaining life of a nuclear power plant in excess of those required to pay future decommissioning costs and to ensure that contributions to the funds are not deducted more rapidly than level funding (taking into account an appropriate discount rate), taxpayers must obtain a ruling from the IRS to establish the maximum contribution that may be made to the qualified fund in any year. The ruling amount may not exceed the amount necessary to fund a percentage of decommissioning costs equal to the percentage of the useful life of the nuclear power plant for which the qualified fund is in effect.[42] A taxpayer is required to include in gross income the amount of nuclear decommissioning costs included in cost of service for ratemaking purposes (sec. 88).

If the decommissioning fund fails to comply with the qualification requirements or when the decommissioning is substantially completed, the fund's qualification may be terminated. The amounts in the fund must then be included in income of the taxpayer upon termination.

A qualified decommissioning fund may be transferred in connection with the sale, exchange or other transfer of the nuclear power plant to which it relates. If the transferee is a regulated public utility and meets certain other requirements, the transfer will be treated as a nontaxable transaction. No gain or loss will be recognized on the transfer of the qualified decommissioning fund and the transferee will take the transferor's basis in the fund.[43] The transferee is required to obtain a new ruling amount from the IRS, or accept a discretionary determination by the IRS.[44]

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fund can make.

[42] For example, in 1979 ElectriCo places in service a nuclear power plant with an estimated useful life of 20 years. In 1984, when the estimated remaining useful life is 15 years, ElectriCo establishes a qualified nuclear decommissioning fund with respect to the plant. ElectriCo's contribution to the fund will be limited to the amount necessary to fund 75% (15/20) of the cost of decommissioning.

[43] Treas. reg. sec. 1.468A-6.

[44] Treas. reg. sec. 1.468A-6(f).

Federal and State regulators may require utilities to set aside funds for nuclear decommissioning purposes in excess of the amount allowed as a deductible contribution to a qualified decommissioning fund. In addition, the taxpayer may have set aside funds prior to the effective date of the qualified decommissioning fund rules. In some cases, a deduction may have been taken for such amounts at the time they were set aside.[45] These nonqualified funds are not eligible for the special rules that apply to qualified decommissioning funds. Since 1984, no deduction has been allowed with respect to the contribution or segregation of nonqualified funds, and the income on nonqualified funds is taxed to the taxpayer at the taxpayer's marginal rate.

Potential effects of restructuring

Amount of deductible contributions

As indicated above, one of the rules applicable to qualified nuclear decommissioning funds is that deductible contributions cannot exceed the amount of nuclear decommissioning costs that are included in the utility's cost of service for rate making purposes (sec. 468A(b)(1)). When a restructuring plan includes the deregulation of electric rates, there may not be a cost of service for ratemaking purposes. If no nuclear decommissioning costs are included in cost of service, no deductions would be permitted for contributions to a nuclear decommissioning reserve fund.

Some States have adopted, or are considering, rules that would require separate ownership of electric generating capacity and the retail distribution system. Implementation of these rules could result in there being no cost of service amount for the taxpayer that owns the nuclear plant, even if a cost of service is provided for the taxpayer owning the distribution system.

Disposition of nuclear power plants

As discussed above, the restructuring of the electric power industry is expected to result in the disposition of generating facilities, including the potential disposition of nuclear power plants. The special rules applicable to qualified nuclear decommissioning funds raise Federal income tax issues when a nuclear plant is sold.

Treasury regulations provide that if a nuclear power plant is transferred from one eligible taxpayer to another eligible taxpayer, the concurrent transfer of the qualified nuclear decommissioning fund associated with the plant will not be a taxable event. For this purpose, an eligible taxpayer is an owner of a nuclear power plant that is eligible to contribute to a qualified nuclear decommissioning fund. A transferor may not be considered an eligible taxpayer if it is

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[45] Prior to July 17, 1984 (the date of enactment of the Deficit Reduction Act of 1984), accrual basis taxpayers could deduct items without regard to the time they were economically performed. Some taxpayers may have taken the position that amounts irrevocably set aside for nuclear decommissioning purposes prior to July 17, 1984, were deductible.

unable to contribute to a qualified fund because its rates are not regulated and it has no cost of service. No gain, loss, income, or deduction is recognized by the transferor, transferee, or qualified fund on account of the transfer of the qualified fund, and the qualified fund's basis in its assets is not changed.[46] The IRS may treat any transfer, whether or not between eligible taxpayers, in a similar manner if it determines that such treatment is necessary or appropriate to carry out the purposes of section 468A.[47]

The transfer of other assets, including nonqualified decommissioning funds, in connection with the transfer of a nuclear power plant is not accorded special treatment. The transferor is required to allocate the amount realized among the assets transferred pursuant to section 1060. The amount realized will include cash and other consideration received by the transferor, plus the amount of liabilities (including decommissioning liabilities) assumed by the transferee. If the transferor is determined to have a fixed and quantifiable liability[48] then a deduction may be available for the amount of nonqualified funds it transfers in satisfaction of an obligation to prefund the expected costs of decommissioning. Although the general economic performance rules would normally prevent the deduction of nuclear decommissioning costs prior to the expenditure of funds for decommissioning, the exception in Treas. reg. sec. 1.461-4(d)(5) may allow deduction if the liability is assumed by the transferee and an equivalent amount is included in the income of the transferor as a result of the transferee's assumption of the liability.[49]

The transfer of the plant normally will not result in income to the purchaser. However, if the amount of cash and cash-equivalents (other than cash and cash-equivalents held in a qualified fund) that is received by the seller to offset future decommissioning costs exceeds the amount paid for the nuclear power plant, the purchaser may be required to recognize such excess as income at the time of sale.

The purchaser's basis in the assets it acquires will be equal to the consideration paid to the seller, plus liabilities that are considered incurred by the purchaser for Federal income tax purposes. Because the cost of decommissioning normally will not be considered incurred under

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[46] Treas. reg. sec. 1.468A-6.

[47] Treas. reg. sec. 1.468A-6(g).

[48] The operator of a nuclear power plant is required to determine the cost of decommissioning and to insure that sufficient funds will be available for decommissioning. Under present law, some consider the determination of the liability for regulatory purposes to be a fixed and quantifiable liability for this purpose.

[49] The IRS has applied this approach in a recent private letter ruling, where it held that the seller had both proceeds and a deduction in an amount equal to the fair market value of the nonqualified funds that were transferred to purchaser to prefund the anticipated nuclear decommissioning liability.

the economic performance rules until decommissioning takes place, the anticipated costs of decommissioning assumed by the purchaser will not increase the purchaser's basis.

b. Income recognition on the provision of services

Present law

Income attributable to the sale or furnishing of utility services to customers by an accrual basis taxpayer must be recognized no later that the taxable year in which such services are provided (sec. 451(f)). The taxable year in which services are provided may not be determined by reference to either (1) the period in which the customers' meters are read or (2) the period in which the customer is billed. The provision of electricity is considered a utility service whose sale is subject to this rule. The IRS has previously taken the position that providers of electricity generally are required to use the accrual method of accounting.[50]

The rule requiring recognition of utility income in the taxable year in which the service is provided was enacted as part of the 1986 Act, to ensure a better matching of income and expense, and to eliminate a source of controversy between utilities and the IRS.[51] Before to the enactment of this rule, an electric utility typically did not recognize income until the customer's meter was read or the customer was billed. As the cost of generating the electricity was typically deducted at the time of generation, a deferral of income was believed to result. This deferral was understood to be unique to the utility industry, and not generally available to other providers of goods and services.

Potential effects of restructuring

Restructuring and any accompanying deregulation of rates for utility services is not expected to have a material effect on the rule requiring recognition of utility income in the taxable year in which the service is provided. Regulation by a public utility commission or similar body is not a prerequisite to the application of the rule. The concept supporting the rule, the matching of items of income and expense, applies equally in a regulated and unregulated setting.

c. Conservation payments

Present law

Residential utility customers are not required to include in taxable income any subsidy provided by public utilities to their customers for the purchase or installation of energy conservation measures that are designed to reduce the consumption of electricity or natural gas, or to improve the management of energy demand, with respect to a dwelling unit (sec. 136)). Before 1997, a partial exclusion for energy conservation payments for nonresidential purposes also was

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[50] Technical Advice Memorandum ("TAM") 9527003.

[51] See *General Explanation of the Tax Reform Act of 1986,* p. 542.

available. In the absence of the statutory rule allowing exclusion, customers that receive such subsidies generally would be required to include them in income. Examples of energy conservation measures included under this rule could include energy efficient heating and air conditioning systems, special thermostats designed to reduce the consumption of energy, and devices for the capture and use of waste heat.

Potential effects of restructuring

Restructuring of the electric power industry could reduce significantly the availability of energy conservation subsidies, and could change the tax treatment of those subsidies that continue to be available. In the past, energy conservation subsidies typically have been provided as part of a demand side management program by electric utilities seeking to avoid or delay the cost of constructing additional generation capacity and/or in response to pressure from the public utility commission to make such subsidies available. Restructuring can be expected to eliminate those programs that were undertaken primarily as a result of public utility commission pressure. Open access to a competitive market in electricity also could eliminate the potential pressure to construct additional generating capacity that demand side management programs were designed to alleviate. Those conservation subsidies that do remain available are likely to be limited to programs initiated by local distribution companies, which are expected to remain as regulated utilities.

The effect of restructuring on those subsidies that continue to be available is uncertain. Although the Code does not explicitly require that the public utility providing the subsidy be a regulated utility for the subsidy to be excluded from income, the legislative history accompanying the provision suggests that the exclusion may have been intended to apply to subsidies provided by regulated public utilities, rural electric cooperatives, and utilities that are owned or operated by a governmental entity, instrumentality or subdivision.[52]

d. Customer deposits and prepayments

Present law

A taxpayer generally is required to include in income any prepayments for goods or services it receives from its customers in the year of receipt. A security deposit, on the other hand, need not be included in income on receipt. Whether an amount received from a customer is a prepayment or a deposit depends upon whether the taxpayer has complete dominion over the

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[52] See, Senate Committee on Finance, *Technical Explanation of the Amendment to Title XIX of H.R. 776 (Comprehensive National Energy Act),* (S. Rept. 102-95).

funds.[53] A taxpayer is not considered to have complete dominion over funds if it has an obligation to repay the funds, whether or not the purpose of the transfer of the funds is to guarantee the customer's payment for goods or services received. These rules apply to both regulated utility and non-utility taxpayers.

Potential effects of restructuring

Restructuring of the electric power industry is not expected to affect the application of these rules. A distributor of electric energy, whether or not regulated, may continue to require deposits from some or all of its customers in the same manner as a regulated provider does currently.

e. Cost of service adjustments

Present law

As described above (Part II.B.l.), rates charged by regulated public utilities are typically established at a level that allows the utilities to recover their costs, including the cost of fuel, and to earn a return on their investment. Because rates are established before the costs of generating the electricity are known with certainty, an estimate of those costs must be used. Where the estimate overstates a utility's costs, allowing the utility to over recover its costs, the amount of the over recovery generally is required to be returned to the ratepayers through a cost of service adjustment, either as a refund or through lower rates for future service.

The Federal income tax treatment of cost of service adjustments depends upon the method in which the utility is required to restore the amount of the over recovery to its ratepayers. Where the cost of service adjustment is accomplished through the reduction of rates on future sales, the taxable income of the utility is determined by the amount it charges for the electric service, without adjustment for the over recovery or its refund.[54] On the other hand, if the repayment of the over recovery is an enforceable obligation of the utility, and must be returned to the ratepayers with interest, the courts have held that the utility derives no benefit from the overpayments and is not required to include them in income in the period the overpayments are charged to customers.[55] If the overpayments are not included in income in the period they are originally charged, no deduction is allowed in the later period in which they are refunded.

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[53] *Indianapolis Power v. Commissioner*, 88 T.C. 964 (1987), aff'd, 857 F.2d 1162 (7th Cir. 1988).

[54] *Roanoke Gas Co. v. United States*, 977 F. 2d 131 (CA4, 1992).

[55] *Houston Industries v. United States*, (Federal Circuit, 1997), affirming 94-2 USTC 50,526.

For assume, suppose two equivalent utilities have received rate orders from the respective public utility commissions based on the same estimate of fuel costs. Assume further that actual fuel costs are 10 percent less than estimated, resulting in an over recovery of costs in the amount of $1,000,000 for the year for each utility. Both utilities are required to refund the over recovery of costs to their ratepayers. Utility A will refund the over recovery by reducing future rates so that estimated fuel costs are under recovered in the following year. Utility A is required to include the $1,000,000 in over recoveries in income in the first year, but will report income of $1,000,000 less than it would otherwise expect to in year 2 when the over recovery is refunded through the lower rates.

The law in Utility B's State requires it to segregate its over recovery of costs and to refund that amount, plus interest, to its ratepayers when ordered to do so by its public utility commission. The PUC orders the refund to be made as a credit on the customers' bills in the following year. Utility B is not required to include the amount of the overpayment in income in the first year, but may not deduct any overpayment in subsequent years.

If a utility originally included the overpayment in income because it appeared that it had an unrestricted right to the funds, and it is later established that the utility did not have such an unrestricted right and is obligated to refund these amounts, Code section 1341 may apply. If applicable, section 1341 allows tax in the year of repayment of the overcharge to equal the lesser of: (1) the amount due if the restoration of the overcharge were treated as a deduction in the year of its restoration; or (2) the amount due if the overcharge were not allowed as a deduction, less the decrease in Federal income tax that would result if the over recovery had been excluded from income in the prior year.

Potential effects of restructuring

Regulatory cost of service adjustments would not be expected in a completely rate deregulated environment. The Federal income tax treatment of any cost of service adjustments that may be ordered as part of the transition to a restructured, unregulated industry would be expected to follow present law, absent a provision specifically addressing the tax consequences of such adjustments.

Following deregulation, contracts for the sale of electricity may include fuel adjustments similar to those included under the current regulatory environment. It is expected that similar rules would apply to adjustments made pursuant to private contracts as apply to regulatory adjustments.

f. Cancellation of supply contracts

Present law

Regulated utilities frequently enter into long-term, fixed price contracts in order to guarantee supplies of fuel. In addition, utilities may have been required to enter into long-term contracts to purchase the output of cogeneration and other small power producers under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). If the payments required by these contracts require the payment of above-market rates, or require the purchase of electricity at the time the utility has excess generating capacity, the utility may seek to cancel the contract through the payment of a settlement or damages to the other party.

The IRS has allowed taxpayers to deduct amounts paid to buy out and terminate supply contracts as ordinary and necessary business expenses in the year they are paid.[56] However, the IRS also has ruled that, where the utility enters into a revised contract with the same supplier as part of the transaction canceling the first contract, the cost of canceling the first contract should be capitalized and recovered over the length of the new contract.[57]

Potential effects of restructuring

A significant number of supply contracts with PURPA suppliers have been canceled in anticipation of, or in response to, the restructuring of the electric power industry. This anticipates an overall decrease in the price of electricity as a result of restructuring, making it more likely that a fixed price supply contract may be viewed as disadvantageous. Restructuring through deregulation of rates could also prevent IOUs from passing through the costs of disadvantageous supply contracts to their customers, increasing the likelihood that the utilities will seek their cancellation. Finally, the ability to recover at least a portion of stranded costs through temporary rate provisions may encourage utilities to make payments to cancel disadvantageous contracts, so that the amount of stranded cost attributable to such contracts can be measured and, to the extent allowed, recovered.

g. Contributions in aid of construction

Present law

In the case of a corporation, gross income does not include any contribution to the capital of the taxpayer. For this purpose, contributions to the capital of a corporation do not include any contribution in aid of construction or any other contribution as a customer or potential customer, except in the case of water and sewerage disposal utilities (sec. 118)). The basis of any property that is acquired as a nontaxable contribution to capital, or with the proceeds of a nontaxable contribution to capital, is zero (sec. 362)).

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[56] PLR 9615028 and PLR 1999 13032.

[57] TAM 9334005.

For example, if an IOU requires new customers to pay the cost of extending the existing wires to the customer's premises, the IOU is required to include such amount in income and may depreciate the cost of the additional wires. The contribution is denied tax free treatment (under Code section 118) because the contribution was made by a customer in that role. On the other hand, a contribution received by an IOU from an independent power producer as reimbursement for construction of interconnection facilities would not be disqualified automatically from nontaxable contribution treatment, since the contribution is being made by a supplier in its capacity as a supplier, and not by a customer.[58]

Potential effects of restructuring

The contribution to capital rules are not affected by whether a utility is regulated. Accordingly, the rules would continue to apply as under present law in a deregulated environment.

h. Involuntary conversions

Present law

Under section 1033, gain realized by a taxpayer from certain involuntary conversions of property is deferred to the extent the taxpayer purchases property similar to, or related in service or use to, the converted property. To qualify, the replacement property must be acquired within a specified period of time, generally two years. The taxpayer's basis in the replacement property generally is the same as taxpayer's basis in the converted property, decreased by the amount of any money or loss recognized on the conversion, and increased by the amount of any gain recognized on the conversion. Involuntary conversions include the loss of property as a result of its destruction, theft, seizure, requisition or condemnation. Involuntary conversions also include sales of property under the threat or imminence of requisition or condemnation (sec. 1033(a)). Sales of property to a private party in order to comply with a government order, such as an order of divestiture in an antitrust case, generally have not been considered involuntary conversions for this purpose.

Potential effects of restructuring

Certain jurisdictions have adopted, or are considering, rules that would require the separate ownership of generation and distribution assets. A sale of assets under such circumstances may not be eligible for involuntary conversion treatment under section 1033. Even if the sale were eligible for involuntary conversion treatment, gain deferral would be available only if the proceeds of the sale were invested in replacement property within the specified period of time. If the rule

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[58] PLR 9327019, Notice 88-129.

requiring separate ownership prevents reinvestment in assets that are similar or related in service or use to the converted property, gain deferral would not be available.

3. Deferred Tax Accounts: Financial, Regulatory, and Tax Accounting

Financial accounting

A deferred tax account[59] is required whenever temporary differences exist between Federal income tax accounting and the financial accounting treatment of an item. Where the difference will result in taxable amounts in the future, a deferred tax liability is created. For example, if accelerated depreciation deductions are allowed for Federal income tax purposes, but not for financial accounting purposes, additional taxes will have to be paid in the future when the depreciation deductions that were accelerated into the current period are not available. These taxes, measured using current income tax rules and rates, are recognized as a deferred tax liability. The financial accounting expense attributable to these additional taxes is recognized at the same time, making financial accounting tax expense for the period in which the accelerated depreciation is available for Federal income tax purposes greater than the amount actually paid.

A deferred tax asset is recorded for temporary differences that will result in deductible amounts in the future, as well as the anticipated reduction in future tax liability attributable to the carryforward of such items as net operating losses and tax credits. If it is more likely than not that the benefit of some or all of the deferred tax asset will not be realized, a valuation allowance is required to reduce the balance in the account to the amount that is likely to be realized.

The impact of restructuring plans including deregulation on financial accounting deferred tax accounts will vary depending upon the source of the deferred tax asset or liability, as well as the economic effects of deregulation. Accelerated depreciation on property, plant and equipment is believed to represent the largest source of deferred tax liabilities for IOUs. Deregulation should not directly affect deferred tax liabilities recorded as a result of accelerated depreciation.

Deferred tax assets in the public utility industry are frequently associated with the unamortized portion of investment tax credits that were claimed for Federal income tax purposes in earlier years. IOUs generally are allowed to elect to include the benefit attributable to the investment tax credit in the year it is claimed for Federal income tax purposes, or to amortize the benefit over the useful life of the asset on which the credit was claimed. Financial accounting typically will use amortization of the benefit from the investment tax credit where that method is used for regulatory accounting purposes. If restructuring eliminates regulatory accounting, IOUs may be able to accelerate the recognition of any deferred tax assets attributable to unamortized investment tax credits in the year of deregulation.

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[59] Financial accounting for income taxes is governed by Financial Accounting Statement 109 (FAS 109), published by the Financial Accounting Standards Board. The rules herein stated are derived from FAS 109.

Regulatory accounting

Deferred tax accounts also are established for regulatory accounting purposes to reflect temporary differences between Federal income tax accounting and regulatory accounting. Such accounts are described in Part II.B.1. of this pamphlet, with respect to the normalization method of accounting.

4. General Corporate Restructuring Issues

In general

Proposals to restructure the electric power industry could result in a significant reorganization of the businesses currently owned by IOUs. For example, an IOU that has owned generation, transmission, and distribution facilities may dispose of some or all of these activities. In some cases, the IOU may dispose of all the assets and activities of a segment of its business. In other cases, businesses and assets may be combined with those of other providers in new ventures. Some ventures also may involve transfers or participation between tax-exempt and taxable entities.

The disposition or combination of businesses and assets can be structured in various ways, producing different Federal income tax results. Assets or businesses can be disposed of for cash, or through other transactions that are fully taxable. In a fully taxable transaction, gain or loss is recognized in full on the transfer of assets or corporate stock interests. Assets or stock purchased in a taxable transaction obtain a fair market value basis. Depreciable assets then can be depreciated by the purchaser over the appropriate recovery period, or resold for their acquisition basis without further gain or loss. Goodwill, customer base, and most other intangible assets generally are depreciable over a 15-year period; however assets such as interests in land and stock are not depreciable.

Dispositions or combinations also can often be structured in a form that is not immediately taxable. For example, assets or stock generally may be transferred to a partnership in exchange for a partnership interest without incurring tax on the transfer. The partners often can achieve a significant amount of flexibility in the division of their interests in the ongoing venture through different classes of partnership interests. There are certain restrictions on transactions that result in the transfer of appreciated property from one partner to another within specified periods, and also certain restrictions on the nature of certain allocations. However, the partnership form of venture often is considered a fairly flexible form for combination and restructuring of interests.

Corporate combinations and restructurings also can often be structured in a tax-free manner. Generally, contributors can form new ventures or provide for a change in the nature of ownership in an old venture through the various corporate reorganization provisions, or through provisions permitting the transfers of stock or assets tax-free to a corporation controlled by the transferors, in exchange for certain consideration. Generally, stock can be received tax free in such situations (and, in limited cases, securities to the extent of certain securities transferred). Under the Taxpayer Relief Act of 1997 (the "1997 Act"), a limited type of preferred stock that does not participate to any significant extent in corporate growth and that is likely to be (or can be at the option of the holder) redeemed within 20 years could be taxable. In general, however, stock consideration, including stock representing varying interests in the underlying business or businesses, can be received tax free if the requisite continuity or ownership requirements are met.

A corporation also can separate existing businesses through the tax-free "spin off" of a 5-year active trade or business to its shareholders. However, under the 1997 Act, certain planned or related changes of 50 percent or more of the ownership of the distributed or distributing corporation can result in corporate-level tax being imposed on a spin-off if there is gain at the corporate level.

In some cases involving industry restructuring, it is possible that assets still may have a fairly high basis from costs of investment, but may produce less income in a competitive market than originally expected in a regulated market that assured cost recovery. To the extent such assets can generate losses, it could be desirable to structure the transaction in a manner intended to make the greatest use of losses. Taxable sales could generate losses, though use of such losses could be limited if there are not gains or other income against which they can be applied. Certain limitations also apply to the future use of existing (or certain "built-in") losses at the corporate level, if a sufficient amount of corporate stock is transferred (rather than the underlying corporate assets) whether in a taxable or nontaxable transaction. Generally, if more than 50 percent of the ownership of a corporation changes hands within a 3-year period, limitations on the use of losses after such ownership change may apply (sec. 382). These limitations are significantly relaxed if the transfer occurs in the context of certain bankruptcy proceedings.

Some situations may involve new ventures between tax-exempt and taxable entities. Tax-exempt entities holding equity interests in certain business activities conducted in partnership form may be subject to unrelated business taxable income. However, tax-exempt entities generally can sell existing tax-exempt assets without tax to taxable entities that then obtain a fair market value basis. Tax-exempt entities also can hold corporate stock, and generally can hold debt interests in any form of venture, without tax, subject to certain rules such as those relating to debt-financed activities.

Special rules relating to utilities

Public utilities that are corporations are allowed a dividends paid deduction on certain preferred stock issued before October 1, 1942, or issued after that date to the extent the preferred stock refunded or replaced certain debentures issued before that date (sec. 247). A special dividends received deduction computation applies to corporate holders of such stock (sec. 244). Whether or not a proposed restructuring could affect the benefits available under this provision may be a consideration.

The Public Utility Holding Company Act of 1935 generally has restricted the ability of utilities outside a single State to be members of the same corporate group. The impact of the rules of this Act on possible corporate reorganizations also may be a consideration.

C. Tax Provisions Affecting Electric Cooperatives

1. Overview of Cooperatives and Electricity

Brief description of cooperatives

Generally, cooperatives are formed under State "cooperative statutes." Federal tax rules only require that the entity operate on a cooperative basis, which is not defined. Nonetheless, the principal criteria for determining whether an entity is operating on a cooperative basis are ownership of the cooperative is by persons who patronize the cooperative and return of earnings to patrons in proportion to their patronage.[60] The Internal Revenue Service requires that cooperatives must operate under the following principles: (1) subordination of capital in control over cooperative undertaking and in ownership of the financial benefits from ownership; (2) democratic control by the members of the cooperative; (3) vesting in and allocation among the members of all excess of operating revenues over the expenses incurred to generate revenues in proportion to their participation in the cooperative (patronage); and (4) operation at cost (not operating for profit or below cost). Cooperatives may have several types of members.[61] In general, members are those who voice management of the cooperative and who share in patronage capital. Income from sale of electricity may be member or nonmember income, depending on the membership status of the purchase consumer. A municipal corporation may be a member or nonmember of a cooperative.

Structure of electric cooperatives

Cooperatives are involved in all four primary functions of the electricity industry: generation, transmission, distribution and retailing. Generation and transmission cooperatives ("G&Ts") construct and operate power plants (alone or in arrangements with other utilities) and sell electricity at wholesale prices to their distribution cooperatives, which in turn sell electricity retail to consumers. Each cooperative may, in turn, be a member of other cooperatives, including cooperative subsidiaries. G&Ts often join with other utilities to build and operate power generating stations.[62] The joint ventures may own the station as tenants in common, operating the station and sharing its capacity and energy according to various operating agreements, station

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[60] No. 229-2nd T.M. (Tax Management Portfolio), *Taxation of Cooperatives*, p. A-1.

[61] Announcement 96-24, Proposed Examination Examination Guidelines Regarding Rural Electric Cooperatives, 1996-16 I.R.B. 35.

[62] "Virtually all electric cooperatives finance their utility plant through loans from or guarantees by the REA (Rural Electrification Administration)." Announcement 96-24, Proposed Examination Guidelines Regarding Rural Electric Cooperatives, 1996-16 I.R.B. 35.

agreements and load management agreements. In approximately 21 States, the State public utility commission regulates rates charged by electric cooperatives.[63]

2. Present and Prior Law

Taxation of cooperatives and their patrons before enactment of Subchapter T

Before 1951, cooperatives were exempt from Federal income tax. In 1951, Congress passed legislation imposing a corporate income tax on cooperatives, except for so-called "exempt cooperatives." This legislation, together with prior Treasury Department rulings, were thought to impose income tax on all earnings of cooperatives (to the extent they reflected business activity) on either the cooperative or their patrons.

However, several court cases held that noncash allocations of patronage dividends were not taxable to the patrons, even though those patronage dividends were deductible by the cooperative.[64] In 1959, the Treasury Department issued regulations to conform the income tax regulations to those decisions. Under these regulations,[65] amounts allocated to patrons of a cooperative with respect to supplies, equipment, or services, the cost of which were deductible as incurred in a trade or business or for the production of income were includable as ordinary income to the extent the allocations were paid in (1) cash, (2) the fair market value of any merchandise received, (3) the fair market value of any revolving fund certificate, retain certificate, certificate of indebtedness, letters of advice, capital stock, etc., to the extent the allocations were paid with such documents, except that any allocations that are paid under conditions beyond the control of the patron were considered not to have any value. Amounts allocated by a cooperative to patrons for supplies, etc., which were not deductible were not includable in the income of the patron. Amounts allocated by a cooperative to patrons for the purchase of a capital asset reduce the basis of the capital asset to the patron.

Taxation of cooperatives and their patrons after enactment of Subchapter T

As a result of the cases described above, in 1962, Congress enacted a new subchapter--Subchapter T--to the income tax (Chapter 1) to assure income of a cooperative is taxed either to the cooperative or its patrons (secs. 1381-1388). Cooperatives, including tax-exempt farmers'

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[63] Announcement 96-24, Proposed Examination Examination Guidelines Regarding Rural Electric Cooperatives, 1996-16 I.R.B. 35.

[64] See *Long Poultry Farm v. Commissioner*, 249 F. 2d 726 (4th Cir., 1957), 57-2 U.S.T.C. 10,048; affg, 27 T.C. 985 (1957); *B. A. Carpenter v. Commissioner*, 219 F.2d 635 (5th Cir., 1955), 55-1 U.S.T.C. 9259, affg, 20 T.C. 603 (1953); acq. 1958-2 C.B. 4.

[65] These substance of those regulations presently is contained in Treas. Reg. sec. 1.61-5.

cooperatives, and their members are subject to special tax rules under subchapter T of the Code (sec. 1381 et seq.). In general, these provisions operate to treat the cooperative more like a conduit than a separate taxable business enterprise.

For Federal income tax purposes, a cooperative generally computes its income as if it were a taxable corporation, with one exception--the cooperative may deduct from its taxable income patronage dividends paid. In general, patronage dividends are the profits of the cooperative that are rebated to its patrons pursuant to a preexisting obligation of the cooperative to do so. The rebate must be made in some equitable fashion on the basis of the quantity or value of business done with the cooperative. Except for tax-exempt farmers' cooperatives, cooperatives are permitted to deduct patronage dividends only to the extent of net income derived from transactions with its members. The availability of these deductions for the cooperative has the effect of allowing the cooperative to be treated like a conduit with respect to profits derived from transactions with members.

Members of cooperatives who receive patronage dividends must treat the dividends as income, reduction of basis, or some other treatment that is appropriately related to the type of transaction that gave rise to the dividend. For example, where the cooperative provides items for its members, patronage dividends attributable to purchase of the items are treated as a reduction in the cost of the items to the member.

Cooperatives; exemption of electricity cooperatives from Subchapter T

In general, subchapter T applies to tax-exempt farmers' cooperatives (described in sec. 521(b)) or any other corporation operating on a cooperative basis (except mutual savings banks, insurance companies, other tax-exempt organizations, and certain utilities). However, the 1962 legislation provided that the new rules did not apply to ". . . an organization . . . which is engaged in furnishing electric energy, or providing telephone service, to persons in rural areas" (sec. 1381(a)(2)(C)). Similarly patrons of such a cooperative are taxed under the pre-subchapter T rules discussed above. Thus, such a cooperative can claim a deduction for income that is allocated to their patrons, but the patrons need not include such income in their taxable income.[66]

Exemption of rural electric cooperatives

Code section 501(c)(12) provides an income tax exemption for rural electric cooperatives if at least 85 percent of the cooperative's income consists of amounts collected from members for the sole purpose of meeting losses and expenses of providing service to its members.

3. Tax Issues Raised by Restructuring Proposals

[66] See Rev. Rul. 83-135, 82-2 C.B. 149.

It is not clear that a rural electric cooperative can be assured that it will receive at least 85 percent of its income from its members under various restructuring proposals, because fees that the cooperative receives for wheeling electricity through its system and from sales of surplus electricity will not be income from members.

D. Special Energy Tax Incentive Provisions

1. Tax Credit for Electricity Produced by Wind and Closed-loop Biomass Facilities

An income tax credit is allowed for the production of electricity from either qualified wind energy or qualified "closed-loop" biomass facilities (sec. 45). Statutorily, the credit is allowed for production during the 10-year period after the facility is placed in service. The credit is equal to 1.5 cents per kilowatt hour of electricity produced from qualified sources. The credit amount is indexed for inflation. In 1999, the credit is equal to 1.7 cents per kilowatt hour of electricity produced.

The credit applies to electricity produced by a qualified wind energy facility placed in service after December 31, 1993, and before July 1, 1999, and to electricity produced by a qualified closed-loop biomass facility placed in service after December 31, 1992, and before July 1, 1999. Closed-loop biomass is the use of plant matter, where the plants are grown for the sole purpose of being used to generate electricity. It does not include the use of waste materials (including, but not limited to, scrap wood, manure, and municipal or agricultural waste). The credit also is not available to taxpayers who use standing timber to produce electricity. In order to claim the credit, a taxpayer must own the facility and sell the electricity produced by the facility to an unrelated party.

The credit for electricity produced from wind or closed-loop biomass is a component of the general business credit (sec. 38(b)(1)). This credit, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of (1) 25 percent of net regular tax liability above $25,000 or (2) the tentative minimum tax. An unused general business credit generally may be carried back 3 taxable years and carried forward 15 taxable years (sec. 39).

2. Business Energy Tax Credits for Solar and Geothermal Property

Nonrefundable business energy tax credits are allowed for 10 percent of the cost of qualified solar and geothermal energy property (sec. 48(a)). Solar energy property that qualifies for the credit includes any equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat. Qualifying geothermal property includes equipment that produces, distributes, or uses energy derived from a geothermal deposit, but, in the case of electricity generated by geothermal power, only up to (but not including) the electrical transmission stage.[67]

[67] For purposes of the credit, a geothermal deposit is defined as a domestic geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor, whether or not under pressure (sec. 613(e)(2)).

Public utility property is not eligible for the business energy tax credits. For this purpose, public utility property is property used predominantly in the trade or business of the furnishing or sale of (1) electrical energy, water, or sewage disposal services, (2) gas through a local distribution system, (3) telephone service, telegraph service or other communications service, (4) steam through a local distribution system, or (5) transportation of gas or steam by pipeline, if the rates for furnishing or sale have been approved by a governmental unit, agency, instrumentality, or commission.

The business energy tax credits are components of the general business credit (sec. 38(b)(1)). The business energy tax credits, when combined with all other components of the general business credit, generally may not exceed for any taxable year the excess of the taxpayer's net income tax over the greater of (1) 25 percent of net regular tax liability above $25,000 or (2) the tentative minimum tax. An unused general business credit generally may be carried back 3 years and carried forward 15 years (sec. 39).

III. ECONOMIC AND TAX ISSUES ASSOCIATED WITH ELECTRIC POWER INDUSTRY RESTRUCTURING

A. Descriptive Data Relating to the Electric Power Industry

In 1998, production and use of electricity comprised 36 percent of total energy consumption in the United States.[68] Electricity production and consumption constituted 2.7 percent of GDP in 1997.[69] In residential and commercial non-transportation uses, electricity comprised 70 percent of total energy use, while electricity accounted for 34 percent of the energy used by industry.[70]

Providers of electricity

In the United States, electric utilities supply electricity to final consumers.[71] In 1997, there were 242 IOUs, 2,013 public power utilities, and 922 co-ops.[72] On average, the IOUs are larger,

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[68] Energy Information Administration, U.S. Department of Energy, *Annual Energy Review 1998,* July 1999. The Department of Energy estimates that in 1998 the United States consumed 94.23 quadrillion Btu of energy from all sources and that direct consumption of electricity and electrical system energy losses (including consumption of primary energy sources in the production of electricity) accounted for 34.33 quadrillion Btu. (p. 37).

[69] GDP in 1997 totaled $8.1 trillion. In 1997, sales of electricity to ultimate consumers were valued at $215 billion. Energy Information Administration, *Electric Sales and Revenue 1997*, October 1998, p. 6. Comparable data for 1998 are not yet available.

[70] Energy Information Administration, U.S. Department of Energy, *Monthly Energy Review*, August 1999. Electricity comprised less than 0.2 percent of energy used in transportation. These calculations are measured on an energy content basis and include the energy content of the primary energy source lost in the production of electricity. For example, in 1998 the energy content of the electricity used by industry totaled 3.6 quadrillion Btu. An additional 7.5 quadrillion Btu of energy from sources such as coal, petroleum, and natural gas was lost in the production of the 3.6 quadrillion Btu of electricity used. (pp. 27-31).

[71] For a more detailed description of the electric utility industry see, Paul L. Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation*, (Cambridge: MIT Press), 1983, and Paul L. Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives,* vol. 11, Summer 1997, pp. 119-138.

[72] Energy Information Administration, U.S. Department of Energy, *Electric $ales and Revenue, 1997,* December 1998, p.8. There were also 10 Federal power agencies that made sales to ultimate consumers.

serving more customers. In 1997, there were 122 million final customers of electricity. IOUs served 75 percent of the customers, public power utilities 14 percent, and co-ops 11 percent.[73] In 1997, IOUs provided 76 percent of final electricity sales, public power 15 percent, and co-ops 8 percent.[74]

The provision of electricity involves four distinct functions: generation, transmission, distribution, and retail sales. "Generation" involves the creation of electricity. Generation requires boilers and steam turbines, internal combustion engines, nuclear reactors, dams, windmills, and the like. Coal is the primary energy source for most electricity produced in the United States (52 percent), followed by nuclear power (19 percent), natural gas (15 percent), hydro power (9 percent), petroleum (4 percent), and other sources (2 percent).[75] (See Figure 1.) The "transmission" of electricity refers to the transportation of electricity from generation sites to distribution centers. This transmission occurs at high voltage and requires wires, transformers, and substations. Transmission generally involves long-distance transportation of electricity. The "distribution" of electricity refers to the transportation of electricity from distribution centers to customers' homes and businesses. Distribution occurs at low voltage and requires poles, wires, transformers and the like in local areas. The "retailing" function involves metering and billing final customers. Retailing also may require the retailer to contract with generators and owners of transmission and distribution systems for the provision of power.

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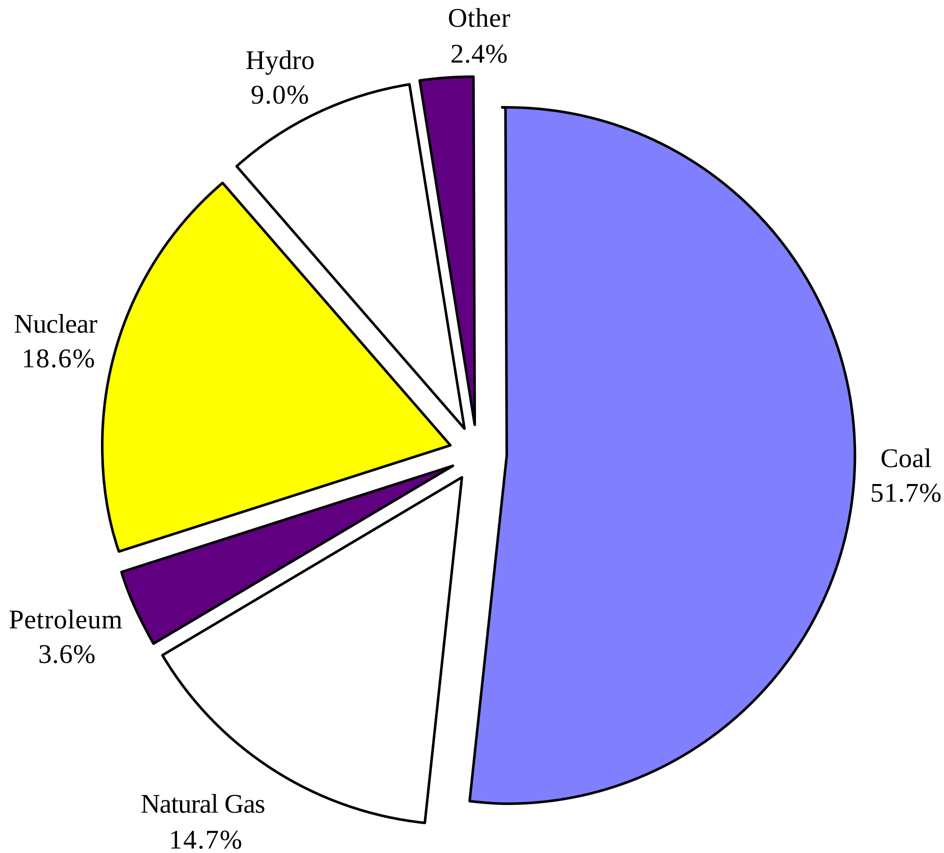
[73] IOUs served 91.6 million customers, public power utilities 16.8 million and co-ops 13.7 million. *Ibid.*, p. 18.

[74] These figures are based on millions of kilowatt-hours, rather than dollars of sales. In 1997, slightly over three trillion kilowatt-hours of electricity were sold by the U.S. utilities. Of that total roughly 2.4 trillion kilowatt-hours were sold by IOUs, 460 billion kilowatt-hours by public power utilities, 263 billion kilowatt-hours by co-ops and 43 billion kilowatt-hours by direct sales from Federal power authorities to final consumers. *Ibid.*, p. 19.

[75] The category "other" includes wood and wastes, geothermal, wind, photovoltaic, and solar thermal among other energy sources. The combustion of wood and wastes accounts for more than half of the electricity produced in this category. Energy Information Administration, *Monthly Energy Review*, August 1999, p. 95 & 101 and Joint Committee on Taxation staff calculations.

Figure 1.--Electric Power Generation by Source, 1998 (percentage)



Historically, electric utilities generally have been granted exclusive geographic franchises in which to sell electricity to retail customers. In many cases, the electric utility, whether an IOU, public power, or co-op, has been vertically integrated, providing each of these four functions. However, some electric utilities produce none of their own electricity, purchasing from others while providing only the retailing and distribution functions. Other electric utilities produce more electricity than their own retail customers consume. These producers provide generation and transmission services to other electric utilities. Generally, in the western United States, IOUs tend to be net purchasers of electricity produced by public power. In the rest of the country, IOUs are net sellers of electricity to public power and co-ops.[76] In 1998, of all electricity produced by electric utilities, IOUs produced 77.6 percent, public power produced 9.0 percent, co-ops produced

[76] Joskow and Schmalensee, *Markets for Power,* p. 19.

4.6 percent, and Federal agencies produced 8.9 percent.[77] In addition, non-utility power producers ("independent power producers") generate 11.3 percent of all electricity (utility produced and independent power produced) in the United States.[78] Comparing these data with the sales data suggest that on a nation-wide basis public power and co-op sectors of the electric utility industry purchase for resale approximately as much electricity as they produce and that IOUs are modest net purchasers of electricity as well.

Users of electricity

The residential sector is the largest end user of electricity, consuming 35 percent of all electricity consumed in 1998. The industrial sector consumed 33 percent of electricity while commercial users consumed 29 percent. (See Figure 2.)

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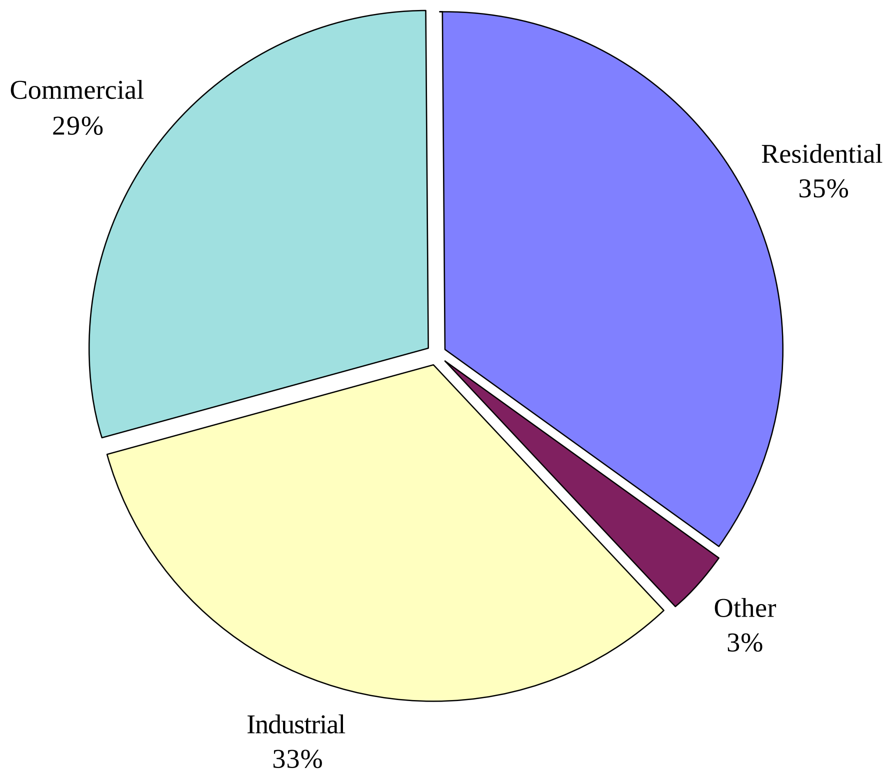
[77] IOUs produced 2,492,919,667 megawatthours of electricity in 1998. Public power produced 288,501,374 megawattshours of electricity in 1998. Of the public power total, 169,984,261 (59 percent) was produced by State power agencies that do not serve a retail function, but rather operate as wholesale providers of electricity to other utilities. Co-ops produced 146,255,087 megawatthours of electricity in 1998. Federal agencies produced 284,494,663 megawatthours of electricity in 1998. Data compiled from U.S. Department of Energy, Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

[78] EIA, *Monthly Energy Review,* August 1999, reports that in 1998 non-utility producers generated 407 billion kilowatt-hours of the 3.6 trillion kilowatt-hours generated. (p. 95).

Figure 2.--Electric Utility Retail Sales By End-Use Sector, 1998 (percentage)



For most of the past 60 years, States have regulated the electric rates that IOUs may charge. In the case of public power and co-ops, public ownership and cooperative member ownership implicitly act as regulators of price. Between 1973 and 1982, electricity prices rose, generally as the cost of primary energy rose. During the last decade, the average price of electricity charged to residential users has increased modestly, while the average price charged industrial users has remained almost unchanged. (See Figure 3.) If these nominal prices are adjusted for general price inflation, the real price of electricity to all consumers has fallen annually for the past decade and is approximately equal to the prices that prevailed in 1973. (See Figure 4.)

Figure 3.--Average Retail Prices of Electricity By Sector, 1973-1998 (cents per kilowatt hours, nominal dollars)

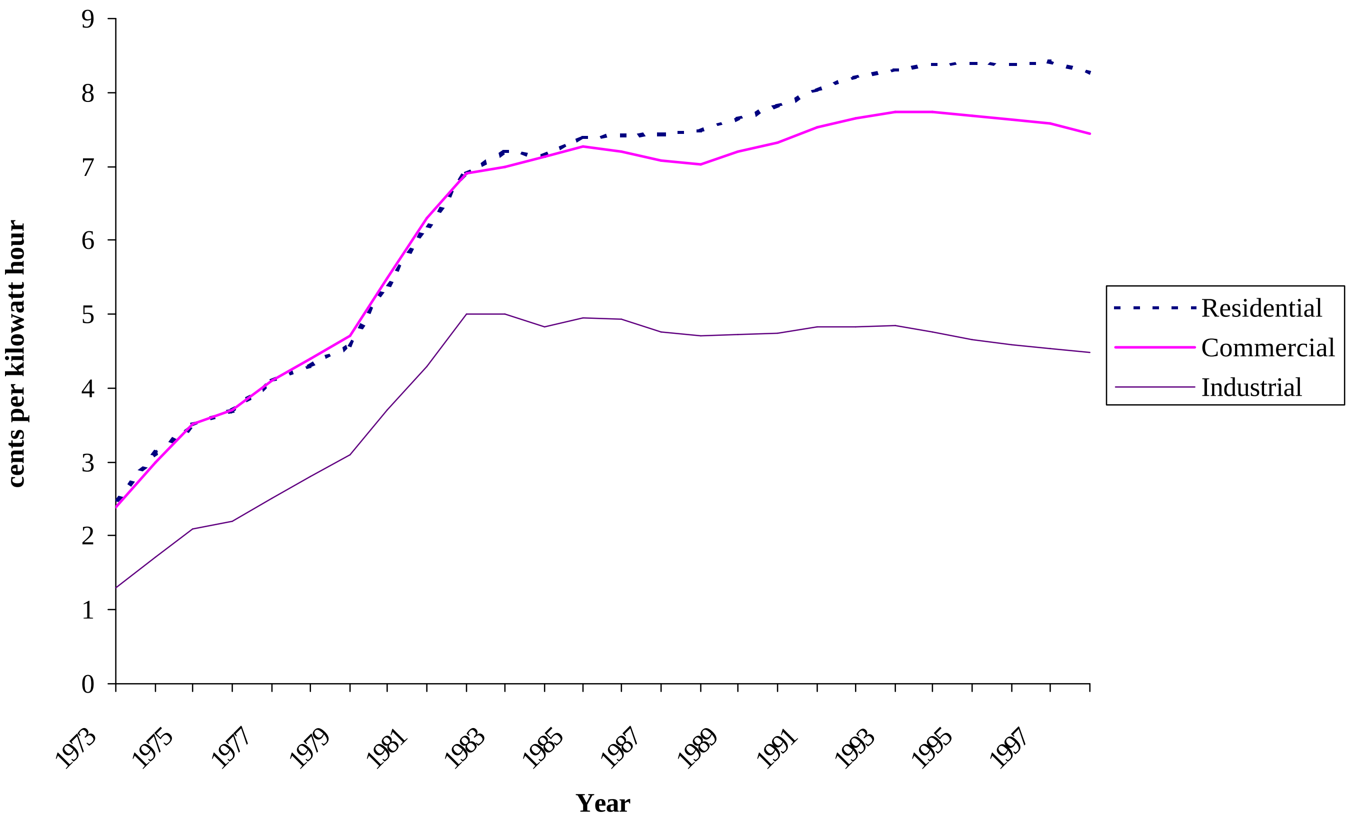
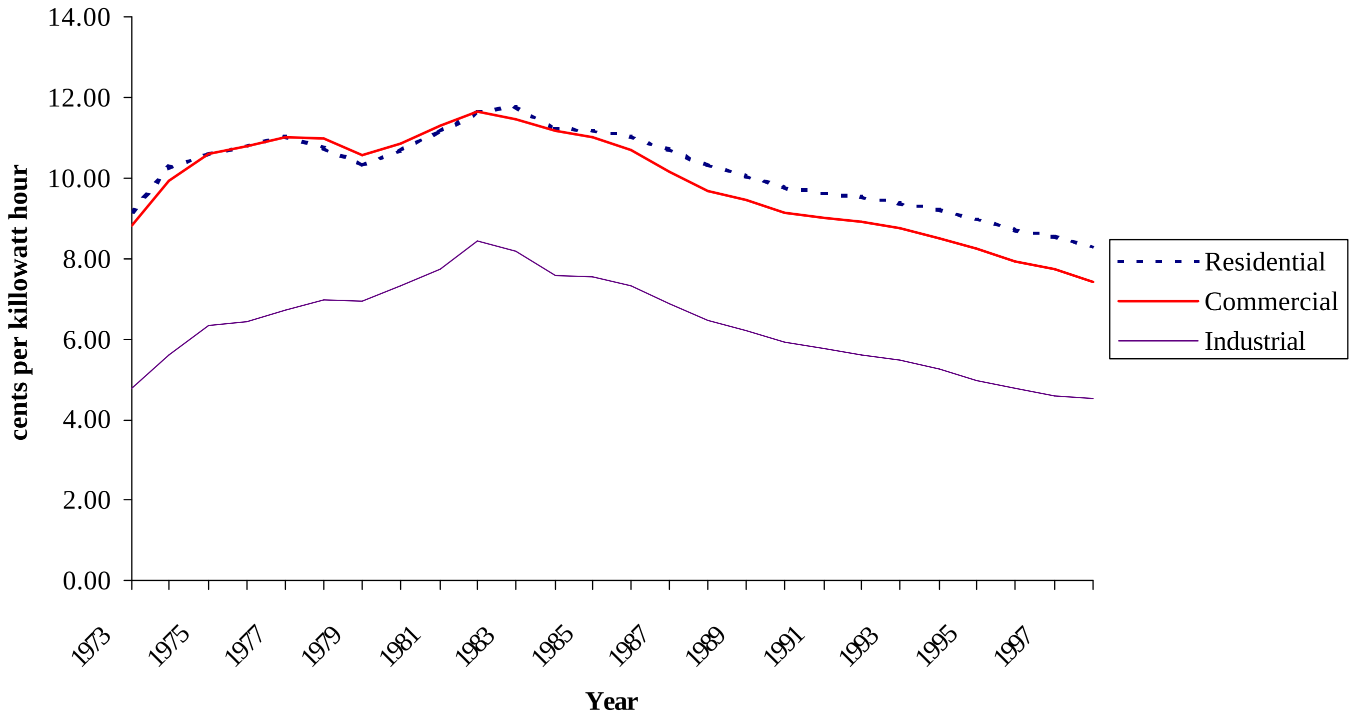


Figure 4.--Average Inflation-Adjusted Retail Prices of Electricity
By Sector, 1973-1998
(cents per kilowatt hours, real 1998 dollars)



B. General Economic Issues Raised by Deregulation of the Electric Power Industry

What is to be restructured?

As noted above, historically most electricity in the United States has been provided by vertically integrated suppliers that perform each of the four functions of generation, transmission, distribution, and retailing. Analysts have argued that vertical integration provides substantial benefits. Because of the physics of electricity, an electric network is integrated and free flowing. Increased demand at one point affects the ability of all other users to use electric-powered equipment and appliances. Likewise, failure in any one part of the generation, transmission, or distribution networks can affect the integrity of the entire system. Different ownership of different parts of the system necessitate negotiation to maintain the integrity of the system. Because system demands are constantly changing, such negotiations might be complex and costly. Vertical integration may enhance the efficiency of the provision of electricity to final users as a vertically integrated supplier internalizes the problems of coordination of generation, transmission, and the distribution of an output whose demand is changing with the time of day and seasons and which must be met in real time if "brown outs" are to be avoided. Hence, vertical integration may promote cost savings and promote system reliability for customers.

In addition, many analysts have long held the view that the provision of electricity may be characterized as a natural monopoly. A natural monopoly is said to exist when substantial economies of scale are created by investment and the investment is so large relative to the market to be served that it would be uneconomic for more than one producer to serve a given market. The substantial physical investments required for generation, transmission, and distribution systems combined with the internalization of the coordination problems discussed above may create such scale economies.

Policymakers long have viewed the existence of natural monopoly as justification of regulation or public provision of electricity to protect consumer interests from monopoly pricing. Other analysts observe that regulation and public ownership can foster inefficiencies. For example, rate of return regulation may promote provision of the good or service by employing more capital, and less labor and other inputs, than would be dictated by a purely cost minimizing manager.[79] The regulatory process may slow investment or disinvestment in response to changes in the consumer market place. Regulation and public ownership may reduce incentives to innovate.

More recently, analysts have argued that to the extent that the provision of electricity has the characteristics of natural monopoly, it is not because there are the characteristics of natural

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[79] Averch, Harvey, and Leland L. Johnson, "Behavior of the Firm under Regulatory Constraint,"*American Economic Review*, 52 December 1962, pp. 1052-1069.

monopoly present in each of the four functions. They note that economies of scale are not so great in generation as to necessitate one generator per region. They note the successful competitive wholesale market in electricity in this regard. Likewise, they argue that the retail sale, metering, and billing of electricity does not require a single metering and billing agent. These analysts argue that the scale of the physical investment and the coordination efficiencies may imply that the only source of natural monopoly lies in transmission and distribution. This has led some to suggest that either the generation or retailing functions of the provision of electricity could be deregulated and opened to market competition to the benefit of consumers. Two basic approaches to restructuring have been broached in recent years. The first, sometimes called the "portfolio manager model,"[80] would have the local distribution utility retain its service area, its retailing function, and regulated status, but would engage in competitive procurement to purchase electricity from suppliers in a competitive wholesale market. The second basic approach might be termed "customer choice" or "retail wheeling."[81] In this approach, retail customers can, individually or in groups, purchase power from independent retailers or wholesalers. The retailers, in turn, would competitively procure power from the wholesale market. The retail customer, or the customer's retail provider, would pay a separate charge to a regulated transmission and distribution company for delivery of the electricity.

Efficiency gains from restructuring

Prices and costs under rate regulation

Utility rate regulators generally permit IOUs to charge prices to recover costs. Similarly, public power authorities and co-ops generally charge prices to recover their costs. Thus, over the long run, the prices charged for electricity reflect the costs of providing electricity. Regulators typically also must approve investments as necessary and appropriate. Thus, the facilities maintained by the utility, and the costs incurred in constructing, maintaining, and operating those facilities, may reflect the regulators' notions of what is appropriate and this might be different from what the market might dictate. The prices permitted generally are based on the average cost of service. Thus, if an electric utility has a high-cost facility and a low-cost facility, the regulators permit the utility to charge a price based on the average cost of constructing, maintaining, and operating the two facilities. Under this structure, current prices charged consumers will embody a "poor" investment (e.g., a high-cost facility).

Effects of restructuring on prices and costs

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[80] Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," p. 127.

[81] *Ibid.*, p. 128.

The rationale for restructuring is that competitive markets provide goods and services at the least cost to consumers. By injecting competition into either the generation function or retailing function, some of the inefficiencies of the present system may be eliminated with the benefits ultimately flowing to consumers. Increased efficiencies may be gained by increased labor productivity, improving the operating performance of existing facilities, and from investments in new facilities. In a more competitive environment, prices would reflect the marginal, or incremental, cost of electricity generation. In the long run, prices embody costs. However, under competition, prices will be determined by low-cost facilities as high-cost facilities will be closed or abandoned.

Many observers believe that the U. S. electric power sector is a reasonably efficient low-cost producer. Electricity rates in the United States are among the lowest of developed countries. One analyst concludes:

> In the short run, the current system does a good job efficiently dispatching generating plants, making cost-reducing energy trades between generating utilities, maintaining network reliability, and dealing with congestion and emergencies. Restructuring for competition and regulatory reform is unlikely to lead to significant short-run cost savings.[82]

This is not to say that consumers would not see price declines in the short run. In the short run, increased competition could lead to prices less than sufficient to cover fully both the fixed and operating costs of certain facilities. While these facilities might remain in service, they would do so at a loss compared to their historic costs. (See the discussion of so-called "stranded costs" below.)

In the longer run, certain uneconomic facilities would be closed and perhaps replaced with new, more technologically advanced facilities. Also, broader arrangements for inter-regional power sales could reduce costs of service. New investments would be made with a view to minimizing costs in a competitive market and such cost savings ultimately should flow to the consumer.

Effects on patterns of use

Economists argue that when prices reflect marginal (or incremental) costs, society's net benefit is being maximized, and that resources are not being wasted. Under regulation, with prices charged equal to average production costs, a factory owner may find it profitable to add additional machinery to produce more widgets during the day shift, rather than to pay overtime to produce the same number of widgets by using both day and night shifts with the existing machinery. However, in order to provide that electricity, the local electric utility may have to bring on line its

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[82] *Ibid.*, p. 124.

most expensive generator and produce the additional electricity at an incremental cost in excess of the price it receives. If the benefit the manufacturer receives from using this additional electricity during the day shift is less than the incremental costs of the electricity's production, this pattern of use wastes society's resources. If the electric utility's price equaled its marginal cost of production, the widget manufacturer might find it more profitable to run the day and night shifts. If the widget manufacturer runs both day and night shifts, the electric utility may not require the additional investment in generating facilities. The effects on the pattern of usage of electricity would be expected to alter the necessary investments in electric utility facilities, perhaps generating additional long-run savings.

Equity issues related to restructuring

Restructuring and prices charged to final consumers

Moving from regulated, average cost pricing, to competitive market pricing generally will change consumers' electric bills. While analysts generally agree that the average price of electricity at the generator or wholesale level will decline, there is no guarantee that *all* consumers' bills will fall. For example, if in a more competitive market there is more peak-load, or time-of-day, pricing some consumers may see their electric bill increase. Alternatively, large users of electricity, such as certain industrial users, may see their prices decline by more than those of residential consumers. On the national level, if restructuring promotes more inter-regional electricity sales, consumers in some areas that currently have very low electricity prices may see their electricity prices rise, while consumers in areas that currently have high electricity prices may see their prices fall. Some may view these benefits of restructuring as being distributed inequitably. On the other hand, the current distribution of prices across consumers may be inequitable.

Some analysts have noted that average cost pricing under regulation may create many potential cross subsidies. For example, if it is more costly to provide electricity to rural customers than to urban customers, but the price charged is the same, then analysts may conclude that urban sales "subsidize" rural sales. Deregulation as a component of restructuring may make some cross subsidies unprofitable. Under the assumptions of this example, prices charged to urban customers may fall, while prices charged to rural customers may rise. On the other hand, some cases of cross subsidy may not involve the generation or retailing functions. To the extent that cross-subsidies arise in the transmission and distribution of electricity, the regulatory scheme that remains on these functions may continue to promote those cross subsidies.

Electricity is a necessity in the modern world and, even if residential electricity on rates average may fall, some believe that paying full market prices for electricity imposes too great a burden on low-income households. For this reason, some have suggested that a restructured electricity industry should include “fees” imposed on *all* customers to provide subsidies for the purchase of necessary electricity by low-income households.[83] Critics of such administrative "fees" observe that such fees are, in fact, excise taxes imposed upon the producer or consumer of electricity. If Federally imposed, such proposals raise Constitutional issues of the delegation of taxing authority and jurisdictional issues within the Congress regarding the origination and oversight of such fees.[84] Others question the fairness of dedicated funding for low-income benefits through a tax on a single service (electricity) rather than drawing upon the General Fund and relying upon a broader tax base if additional revenues are required. A dedicated subsidy for specific purchases may make it difficult for policymakers to assess the overall assistance needs of low-income households when such households may receive general assistance and subsidies to one or more specific purchases of goods or services. Subsidies to specific goods and services may limit the ability of low-income households to allocate resources in a manner to most improve their specific economic situation.

Stranded costs

If restructuring leads to changes in prices or new entry to the market for the provision of electricity, the values of existing assets used to provide electricity may change. Some may view the resulting pattern of gains and losses in asset values as inequitable.

In a regulated environment, where rates have been set on a cost of service basis, IOUs have had an assurance of recapturing asset values by means of a regulatorily established "fair" rate of return that is based on the historical costs of these investments. In a competitive market, there is no comparable assurance of a guaranteed return, and asset values are determined by the current and expected future income streams that the asset can generate. In general, the asset values will be governed by the market estimate of the present value of this expected stream of income. In the competitive environment, it is widely acknowledged that prices for electricity will be lower than those currently set through the regulatory process, and that the market value of certain IOU assets,

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[83] For example, section 401 of S. 1047, "The Comprehensive Electricity Competition Act," (the Administration's deregulation proposal) would provide that each producer of electricity be assessed a "fee," to be determined administratively, of up to 1 mil per kilowatthour of electricity produced. The proceeds from this "fee" would be used, among other purposes, to provide affordable electricity service to low-income customers.

[84] Such proposals are similar to the "E-rate" telecommunications program implemented by the Federal Communications Commission under the Telecommunications Act of 1996. For an in-depth discussion of the Constitutional and jurisdictional issues raised by such proposals see, Joint Committee on Taxation, *Background and Present Law Relating to Funding Mechanisms of the "E-Rate" Telecommunications Program* (JCX-59-98), July 31, 1998, and Part IV of Joint Committee on Taxation, *Present Law and Background Information on Federal Transportation Excise Taxes and Trust Fund Expenditure Programs* (JCS-10-96), November 14, 1996.

particularly in generation,[85] will be lower than their historical costs on the books for ratemaking purposes. As described above (Part II.B.1), this difference in the market value of these assets relative to their value in the ratemaking process (which is the unamortized portion of the historical costs of the asset) has commonly come to be called "stranded costs."[86]

The recovery of stranded costs has become one of the more contentious issues in the restructuring debate. Estimates of the magnitude of these costs range from $10-20 billion to $500 billion.[87] Depending on their magnitude, these costs potentially could bankrupt certain IOUs if the IOUs are held responsible for the stranded costs. While bankruptcies may impose some unique additional costs in the transition to competition (such as assets being tied up in bankruptcy proceedings), it is not obvious that any special steps should be taken to bail out these IOUs and their shareholders and bondholders. The IOUs most likely to go bankrupt will be those that were highly leveraged (that is, those financed with high debt to equity ratios, implying that the IOU's earnings in a competitive environment are more likely to be insufficient to meet the scheduled payments on debts to bondholders, thus precipitating bankruptcy) and/or those with the greatest stranded costs from past uneconomic investments. In other words, these IOUs are more likely to have made poor investments in generation, thus producing high-cost electricity, and/or to have made poor financing choices in the past, thus running greater risks of bankruptcy. Their service territories therefore have the most to gain from a quick transition to competition.

Irrespective of bankruptcy concerns, many observers feel that the recovery of stranded costs should be allowed on the grounds that there was a "regulatory compact" that provided that "prudently" incurred costs would be recoverable in the ratemaking process in exchange for the provision of service at regulated rates to everyone in the service territory. Indeed, the Federal Energy Regulatory Commission ("FERC"), in its Order 888, stated "the recovery of legitimate, prudent, and verifiable stranded costs should be allowed,"[88] and found that this was "critical to the

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[85] The largest stranded costs are believed to be in generation, particularly in nuclear plants. Other stranded costs may include long-term contracts with other generators at above market rates, fuel supply contracts at above market rates, and "regulatory assets"--deferred expenses that appear as assets on the balance sheet and that utilities would be able to recover in the future.

[86] The current discussion of "stranded costs" generally is presented in terms of IOUs. However, as discussed later, the issue is potentially endemic to the entire electric power industry.

[87] Energy Information Administration, U.S. Department of Energy, *The Changing Structure of the Electric Power Industry: An Update*, December 1996, p. 78.

[88] Federal Energy Regulatory Commission, Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, and Recovery of Stranded Costs by Public Utilities/and Transmitting Utilities*, Docket No. RM-94-7-001 (April 24, 1996), p. 451.

successful transition of the electric industry to a competitive, open access environment."[89] Other observers have argued that recovery of stranded costs would inhibit the movement to competition, potentially distort price signals, and reward the most inefficient producers.

To examine the issue of stranded costs from an economic perspective, it is first important to understand that while rate restructuring creates "stranded costs" as defined above, the true economic costs that give rise to "stranded costs" have already been incurred. That is, stranded costs are not a true aggregate economic cost of restructuring, but rather represent simply a calculation of the value of the true economic losses from past investments. From an economic perspective, these costs are considered "sunk" costs. From the standpoint of society as a whole, they are irretrievable losses, and the debate over stranded costs is simply a debate over who should bear the burden of these losses in a transition to competition. Whether the shareholders and bondholders of the IOUs should bear these costs, or whether the existing or future customer base, on behalf of whom the costs were incurred, should bear these costs, is a debate as to what is "fair," and economists have no special expertise to inform this debate. However, the manner in which these costs are assigned, as opposed to whom they are allocated, might have important implications for the economically efficient operation of electricity markets.

An abrupt transition to competition, in which shareholders were held responsible for stranded costs of IOUs, and where customers could subsequently shop around for the best price, would result in economically efficient electricity markets as a consequence of the ability of prices to adjust to changing market conditions.[90] However, an abrupt transition in which the existing customer base were immediately required to pay for the stranded costs, in exchange for open competition on electricity rates, would result in economically efficient electricity markets for the same reasons. The use of "exit fees" that are designed as lump-sum payments and do not change the price of electricity at the margin (i.e., the magnitude of the payment is determined in advance, and is independent of actual future electricity use) is an example of the latter approach. "Exit fees" are charges assessed a utility customer who formerly paid at regulated rates and who chooses to become an "unbundled" (i.e., elects to begin to pay competitive rates for the generation component of electricity) customer of that utility. The "exit fee" is designed to cover the portion of stranded costs that such customer is deemed to be responsible for.[91]

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[89] *Ibid.*, p. 454.

[90] This discussion assumes that there are no "negative externalities" to consumption (i.e., no costs to others as a result of private consumption), and that there are no natural monopoly conditions that apply.

[91] See *ibid.*, 143-157, for a discussion of the estimation of stranded costs and exit fees. Also, see discussion of related “fees” and footnote 84, above, for issues related to the determination of whether a charge is a “tax” or a “fee”.

Some schemes for the recovery of stranded costs will delay true competition in the electricity markets and also the benefits that flow from true competition in the form of greater efficiency of these markets. The primary example of this entails imposing a fee per kilowatt hour on the distribution of electricity, and dedicating this fee to the recovery of stranded costs (i.e., giving the fee to the utility that served the customer in the regulated environment, regardless of who serves the customer in the competitive environment). These fees are the economic equivalent of excise taxes, and as such have the negative effects of such taxes, namely distortion of relative prices (i.e., electric energy will be artificially made more expensive than other forms of energy, relative to what would prevail in fully competitive conditions). Such price distortions result in economically inefficient choices. For example, a consumer might be willing to pay 8 cents per kilowatt hour for electricity, and a potential supplier might be willing to provide it for 6 cents per kilowatt hour based on the true economic costs of production. Both parties would be made better off by the transaction, but a sale will not take place if a stranded cost fee is imposed that exceeds the difference between the price the buyer is willing to pay and the seller is willing to sell. For example, if an exit fee of 3 cents per kilowatt hour is charged, the cost to the consumer will now be 9 cents, and a transaction will not take place. The consumer might instead elect to consume energy in a different form, despite the true economic costs of the alternate energy source being greater than the true economic cost of electricity, as long as the alternate energy source is less costly than the fee inclusive price of electricity. Such choices are economically wasteful, leading to an under-consumption of electricity, and potentially an over-consumption of alternate energy sources.

Other issues

System reliability.--Most analysts agree that regulators strive to ensure system reliability and that the electric service provided in the United States is very reliable. This may be a source of economic inefficiency. Regulation may have fostered excessive investment in capacity to meet demands that reasonably might be expected to occur infrequently. Investment in reliability costs society resources. One estimate has placed the costs of electricity provided to meet such infrequent demand as costing $3.60 per kilowatt hour.[92] If the consumers who use this electricity at such times would not be willing to pay $3.60 per kilowatt hour to avoid a power outage, then economists would conclude that society's resources have been invested wastefully. If under restructuring, market demand determines investment, such additional investments in system reliability will not be made if investors do not believe they will be able to earn a sufficient return

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[92] Energy Information Administration, U.S. Department of Energy, "Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities, A Preliminary Analysis Through 2015," August 1997, p. 15. The Department of Energy observes that "[t]he standard measure of reliability on which systems have been designed is to provide enough generating capacity so that only one day of capacity shortage results every 10 years. The implementation of this standard means that the cheapest capacity . . . in service . . . is used 8 to 10 hours per year."

on their investments. As a result, the electric system under restructuring may be less reliable than under regulation. On the other hand, some aspects of reliability may improve. If there is competition in retailing, one area in which competition might occur is customer service.

Environmental concerns.--Environmental regulation of the electric power industry generally is independent of the industry's current structure. The primary environmental regulations result from the Clean Air Act and the operation of nuclear reactors.[93] Restructuring of the generation or retailing functions of the electric power industry generally would not alter the applicability of any of these standards. To the extent that rate regulation or public ownership has been used to foster certain environmental goals, restructuring could alter environmental outcomes. In addition, to the extent that air pollution increases with the amount of electricity produced, restructuring by reducing prices may increase the demand for electricity. On the other hand, if more fuel efficient natural gas combined cycle turbine technology displaces certain older generating facilities or if time-of-day pricing reallocates when the demand occurs, total air pollutants could fall.

Some have suggested that under deregulation the environmental goals fostered by regulators could be maintained through the imposition of a "fee" on producers or consumers of electricity with the proceeds used to finance programs such as energy conservation and energy efficiency measures which currently are mandated by public utility commissions.[94] Critics of such administrative fees observe that such fees are, in fact, excise taxes imposed upon the producer or consumer of electricity. If Federally imposed, such charges raise Constitutional issues of the delegation of taxing authority and jurisdictional issues within the Congress regarding the origination and oversight of such fees.[95] Because any tax distorts economic choice, such taxes may be inconsistent with one of the stated purposes of deregulation, to wit, to improve overall efficiency in the production and consumption of electricity. On the other hand, if policymakers conclude that there is environmental harm caused by the consumption of "too much" electricity such a tax on electricity might reduce overall consumption of electricity and lead to a concomitant reduction in any environmental harm caused by the production and consumption of electricity.

Consolidation in the electric power industry.--As was noted above, coordination of generation, transmission, and distribution may create certain operating efficiencies. Under today's

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[93] See the discussion below relating to nuclear decommissioning trust funds.

[94] For example, section 401 of S. 1047, "The Comprehensive Electricity Competition Act," (the Administration's deregulation proposal) would provide that each producer of electricity be assessed a "fee," to be determined administratively, of up to 1 mil per kilowatthour of electricity produced. The proceeds of this fee could be used, among other things, to finance energy conservation programs and research into new technologies.

[95] See footnote 84, above.

regulated environment the ability of any utility to exploit these coordination efficiencies generally is limited to coordination within one utility's defined service area. In a deregulated environment, if such efficiencies are significant, they may provide the rationale for mergers between owners of transmission systems or distribution systems.

C. Tax Issues Raised by the Restructuring of the Electric Power Industry

1. Special Status of Public Power and Cooperatives

Overview of cost of capital in the electric power industry

As discussed in Part II.C., above, public power and co-ops operate in a tax environment that is significantly different from the IOUs, which represent the majority of the electric power industry. Public power entities, as government entities, are not subject to the corporate income tax and may issue tax-exempt bonds to help finance their investments.[96] Co-ops, which are owned by the patrons of the system, are accorded pass-through status for Federal income tax purposes. That is, there is no corporate level income tax and dividends from any earnings are taxed only as income at the individual, or member, level. In certain circumstances the dividends received by individual taxpayers may be excludable from taxable income at the member level as well as excludable at the entity level. Co-ops' investments also benefit from favorable loans from the Federal Government. The cost of capital of both types of entities is lower than it would be if they were subject to corporate income tax.

In the absence of rate regulation, IOUs also may face a higher cost of capital in the market. As regulated utilities, for whom regulators generally have let earnings be neither too high nor too low, investors have required lower rates of return than if earnings were subject to the vagaries of a more competitive market. The relative security of revenue under regulation also may have encouraged more reliance on debt finance than would be appropriate in a more competitive market. Thus, restructuring may lead all segments of the electric power industry to alter their financial structures.

Tax-exempt financing

The ability to finance capital and operating costs with tax-exempt bonds may substantially reduce the cost of debt finance. To illustrate, assume the interest rate on taxable debt is 10 percent. If an investor in the 36-percent marginal income tax bracket purchased a taxable debt instrument, his after-tax rate of return would be the 10-percent interest less a tax of 36 percent on the interest received for a net return of 6.4 percent. If as an alternative this investor could purchase a tax-exempt bond, all other things such as credit worthiness equal, he would earn a better after-tax return by accepting any yield greater than 6.4 percent.[97] In the market, the yield spread between a tax-exempt bond and comparable taxable bond is determined by the marginal buyer of

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[96] Certain IOUs, referred to as local furnishers, also may use tax-exempt bonds to finance their facilities. (See Part II.A., above.)

[97] More generally, if the investor's marginal tax rate is t and the taxable bond yields r, the investor is indifferent between a tax-exempt yield, r_e, and $(1-t)r$.

the bonds; in today's market, yield spreads are generally less than 28 percent.[98] Because the yield spread arises from forgone tax revenue, economists say that tax-exempt finance creates an implicit subsidy to the issuer. However, with many investors in different tax brackets, the loss of Federal receipts is greater than the reduction in the tax-exempt issuers' interest saving.[99] The difference accrues to investors in tax brackets higher than those that would be implied by the yield spread between taxable and tax-exempt bonds.

Industry restructuring might have two distinct effects on public power and IOUs that qualify for tax-exempt financing as local furnishers. First, if these utilities must use taxable bonds to finance generation facilities, their cost of capital is likely to rise.[100] Because competitors attempt to price their services to recover their capital costs, in the long run, prices of electricity provided by these generators might rise. In addition, because tax-exempt financing lowers the cost of debt capital, electric service providers that issue tax-exempt bonds may rely more heavily on debt

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[98] For example, while not comparable in security, market trading recently priced 30-year U.S. Treasuries to have a yield to maturity of approximately 6.055 percent. Prices for an index of long-term tax-exempt bonds have produced a yield to maturity of approximately 5.70 percent. See, *The Bond Buyer,* 330, October 1, 1999, p. 42. Again ignoring differences in risk or other non-tax characteristics of the securities, the yield spread implies that an investor with a marginal tax rate of 6 percent would be indifferent between the Treasury bond and the average high-yield tax-exempt bond. The yield to maturity on 10-year U.S. Treasuries was 5.789 percent, while prices on an index of tax-exempt bonds with 10-year maturities produced an average yield of 4.93 percent, implying investors with a marginal tax rate of 16 percent would be indifferent between the Treasury bond and the tax-exempt bond.

[99] The Federal income tax has graduated marginal tax rates. Thus, $100 of interest income forgone to a taxpayer in the 31-percent bracket costs the Federal Government $31, while the same amount of interest income forgone to a taxpayer in the 28-percent bracket costs the Federal Government $28. If a taxpayer in the 28-percent bracket finds it profitable to hold a tax-exempt security, a taxpayer in the 31-percent bracket will find it even more profitable. This conclusion implies that the Federal Government will lose more in revenue than the tax-exempt issuer gains in reduced interest payments.

[100] As discussed in Part II.A., above, restructuring could cause outstanding bonds to lose their tax exemption. In practice, when an outstanding tax-exempt bond becomes taxable the issuer typically pays the Federal Government a negotiated settlement amount. Such payments would not raise the total interest expense to that incurred by an issuer who has issued taxable bonds unless the negotiated settlement amount equals the yield spread between the formerly tax-exempt bond and a comparable taxable bond. Moreover, even in such case, the "tax" recovered when an outstanding tax-exempt bond becomes taxable is less than the amount of tax that would have been paid had the bond initially been sold as a taxable bond offering taxable interest for the reasons explained in the preceding footnote.

finance than other providers. Loss of the ability to use tax-exempt financing may cause the affected entities to adjust their financial structure in the long run. In the short run, investors may view such providers as riskier investments than others because of their higher leverage ratios.

On the other hand, if these electric service providers were permitted to retain their ability to receive tax-exempt financing, they might have a considerable cost advantage over other generators in a deregulated market for generated power. The market share of such generators would expand and the implicit Federal subsidy to electric generation and certain investors might increase. In order to keep these providers from exploiting their capital cost advantage, the scope of restructuring may have to be smaller, perhaps by not permitting such generators to interconnect with the IOUs. Limiting interconnection, however, would limit the scope for exploiting system rationalization, inter-regional power sales, and efficiency gains.

A second effect that restructuring could have on current electric power industry beneficiaries of tax-exempt bonds is the so-called stranded cost problem. Analysts usually refer to the stranded cost problem in the context of privately owned facilities, but the problem can arise for public power as well. Bonds outstanding today have financed facilities. The prices charged for the electricity produced by these facilities is based on a non-competitive market in which the price is sufficient to meet the debt service demands of the bond. Under restructuring, the wholesale price of electricity may generate revenues insufficient to meet the debt service requirements of the facilities. In such a situation, to avoid possible default on the bonds, the utility may have to draw down reserves or devise some method to recover the original investment in the facilities.[101]

Exemption of co-op income from corporate level tax

Co-ops generally are treated as pass-through entities, exempting certain income they earn from corporate income taxation. Income paid as patronage dividends is deductible and, thereby, exempt from tax at the entity level. The dividends received by the member or patron generally may remain taxable to the recipient if the recipient is a business that previously has deducted expenditures related to its purchase of electricity from the co-op. If the recipient is an individual taxpayer, in most cases dividends are exempt from tax at the individual level as well as the entity level. In addition, as described in Part II.C., above, a rural electric co-op is exempt from corporate income tax regardless of whether it distributes its income to members provided 85 percent of the co-op's income consists of amounts collected from members.

Most economists believe that the corporate income tax effectively taxes the returns to equity investments in the corporate sector. That is, the after-tax rate of return to an equity investor is lower than it would be in the absence of the tax. The reduced rate of return may discourage equity investment in taxable corporations. In this view, a co-op's exemption from the corporate income tax encourages equity investment in the enterprise. The exemption from tax at the

[101] The problem of stranded costs was discussed in more detail in Part III.B., above.

individual level would magnify this effect for individual investors. Because an equity investor in a co-op can earn the pre-corporate tax rate of return, if the incremental source of financing in electric utility operation is from equity capital, the co-op may have a cost of capital advantage compared to IOUs.[102] In addition, co-ops may borrow from the Federal Government at favorable rates compared to the borrowing rates of IOUs. Thus, the cost of debt capital also is more favorable than that of many IOUs.

Implicit subsidies to the cost of capital of some electric service providers and not to others may encourage an inefficient pattern of investment in facilities. In addition, by paying patronage dividends to members or patrons based on their use of electricity, the co-op reduces the effective price of electricity to the members or patrons. The effective price members or patrons pay may not reflect the true cost of providing the service and consumer choice may be distorted. These consumers may consume more electricity than they otherwise would. An increase in demand for electricity as the result of this price effect could lead to an inefficient over-investment in facilities to meet the demand. However, if restructuring were accompanied by a loss of the tax-favored status of electric co-ops, the prices co-op members face might rise as a result of the termination of current subsidies.

One of the policy reasons behind the creation of favorable financing sources for cooperatively owned utilities was to offset the higher cost of providing service in certain areas. These high costs were generally attributable to the distribution and retailing of the electricity in rural areas, rather than in the generation of electricity. However, the tax and other benefits available to cooperative ownership are not limited to the distribution and retailing functions or to co-ops serving rural areas. Moreover, the cost conditions that motivated the original policy may no longer be valid in all areas served by co-ops.

If, in a restructured market, cooperatively owned generation facilities retain favorable costs of equity and debt capital, they may gain a cost advantage over other generators of electricity. However, the cost of equity capital advantage may be limited in practice from the requirement that equity come from co-op members, rather than from the public capital markets. Moreover, the rule requiring 85 percent member-source income may limit the ability of some cooperatively-owned generators to expand beyond their primary service area and retain a cost of capital advantage. If restructuring permitted such generators to expand and seek new customers, they would only retain their tax-favored cost of capital advantage if the new customers were made members of the cooperative. The form restructuring takes may be important in this regard. If restructuring follows the portfolio manager model, where pre-existing electric service providers purchase electricity

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[102] Similar to the analysis for tax-exempt bonds, if alternative equity investments offered an expected rate of return of r, a co-op need only offer an individual investor an expected rate of return of r_c, where $r>r_c>r(1-t)$ when the individual investor's investment income is otherwise taxed at a marginal rate of t. The co-op benefits from a lower cost of equity capital ($r_c<r$) and the individual investor receives a higher after-tax of return ($r_c>r(1-t)$.)

from a competitive market of electricity generators, it may be difficult for a cooperatively owned generator to expand and continue to meet the 85-percent test. On the other hand, if restructuring follows the customer choice model and if a cooperatively owned generator also acts as a retailer, any new customer could become a co-op member.

As with public power, there may be some cooperatively owned facilities that become uneconomic in a deregulated market. At competitive wholesale prices for electricity, these facilities may be unable to generate revenues sufficient to service the debt incurred to build the facilities or to pay competitive returns to equity investors. This again is the issue of so-called stranded costs which was discussed above.

2. Special Energy Tax Incentives

As discussed above in Part II.D., numerous provisions of the Code provide certain incentives for the production of electricity by specified means, such as by wind, solar, or "closed loop" biomass facilities. Such special provisions have been justified on various grounds (e.g., they produce less pollution, reduce our reliance on foreign energy, etc.), but these provisions represent a departure from the purely competitive model, where prices are determined solely by the workings of the market place, rather than being influenced by government intervention that favors particular activities.

If these special tax incentives are designed to overcome specific market failures, they may result in more socially efficient economic outcomes. For example, if pollution costs from the burning of fossil fuels for electricity generation are not internalized in the price of electricity, there will be over-consumption, from an overall social perspective, of electricity produced from fossil fuels. Economists generally maintain that the best approach to deal with this "negative externality" is to set an appropriate tax on the activity that produces the negative externality. The alternative of granting tax incentives for alternative forms of energy production might yield improvements over the competitive market outcome, although this would not necessarily be the case.[103] If the cost of the subsidies exceeds the negative externalities from the burning of fossil fuels, a worse outcome could result as the cost of the subsidies would exceed the value of the

[103] Subsidizing an alternative form of energy does not help to get the total price to the consumer equal to the total social costs of the consumption of the good with negative externalities. Having a good's price embody all costs of its consumption is a desirable objective from an economic efficiency standpoint. Only a tax at a rate equal to the negative externality (called a "Pigouvian" tax) will equate the price with the total social costs of consumption. Subsidizing the alternative form of energy would only be appropriate, from the standpoint of economic efficiency, if there were "positive externalities" from the consumption of such energy. Positive externalities exist where the private consumption of a good leads to benefits, rather than costs, to third parties.

benefits of reduced pollution.[104] Whether good or bad, these special tax incentives are not part of the "regulatory framework," however, and they are not necessarily jeopardized by the restructuring proposals under consideration.

At the State level, the dismantling of parts of the regulatory apparatus could result in fewer investments in "alternative" generating capacity.[105] Under a regulatory regime, such facilities might be built, despite higher costs of generation, if the State public utility commissions can be convinced that they offer positive benefits relative to conventional generating capacity. (See above discussion on "stranded costs" of high-cost generation.) Under these circumstances, investors will be willing to build these facilities provided the ratemaking process gives them an adequate rate of return on their investment. Under competition, with no assurance of a return guaranteed by a ratemaking process, investors will only build these facilities if they offer the promise of a competitive rate of return. Even without public utility commission ratemaking, State legislatures could still choose to subsidize "alternative" generating capacity through incentives in State tax codes, or through direct expenditures.

Alternatively, States or the Federal Government could require that a minimum percentage of the electricity provided by deregulated sellers be derived from certain “alternative” sources.[106] If a demand for “alternative” generating capacity were mandated, sellers of electricity may bid up the wholesale price paid to suppliers of electricity from “alternative” sources. With higher wholesale prices, investors may find investment in such projects profitable even though conventional generation capacity can produce electricity more cheaply. Retail sellers of electricity

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[104] The value of a tax preference may not be equal in all situations. For example, public power producers and co-ops generally, and in certain cases IOUs, do not benefit directly from the tax credit for wind and closed-loop biomass or the tax credit for solar and geothermal property. To obtain the benefit of these tax incentives, public producers, co-ops, and IOUs may work with third parties. However, this may decrease the efficiency of the tax preference and reduce the incentive to switch to a tax-preferred energy source.

[105] Other conservation measures that are sponsored through the regulatory process also may disappear. An example of this might be the "demand side management" programs, whereby utilities provide free energy conservation materials to households, such as energy efficient light bulbs. This does not imply that conservation measures will cease with the advent of more competitive markets, but that the conservation measures undertaken will be dictated by pricing signals and private actions (or, potentially, other interventions by State legislatures), and not by public utility commissions.

[106] For example, section 402 of S. 1047, “The Comprehensive Electricity Competition Act,” (the Administration’s deregulation proposal) would require that in 2010 at least 7.5 percent of the sales of each retail seller of electricity be derived from solar, wind, geothermal, or biomass sources.

would attempt to recoup the higher costs of electricity from “alternative” sources by charging higher retail prices for electricity. To the extent that such “alternative” energy sources are not cost competitive with conventional generation, mandates create a subsidy from rate payers to the suppliers of electricity from “alternative” sources.[107]

Both limited mandates and targeted subsidies and tax preferences may not be the most efficacious way to reduce conventional electricity generation. By providing financial incentives to a limited set of alternatives taxpayers may forgo another alternative that can achieve the same result at less cost to society. If both mandates and subsidies are employed simultaneously, the total effective subsidy may vary by type of “alternative” source and more total subsidy may be provided to investors in certain “alternative” sources than is necessary to induce the desired aggregate increase in “alternative” capacity.

3. Nuclear Decommissioning

Under present law, special tax treatment is allowed for set-asides for the future decommissioning of nuclear power plants. (See previous discussion in Part II.B.2.a.) The rationale for this provision of current law is to assure that there is adequate funding available for the high cost of decommissioning these plants at the end of their useful life. This tax treatment also helps to spread the costs of the decommissioning over the life of the plant, rather than burdening future ratepayers with the entire expense. Under competition, there may still be a compelling public policy rationale for some form of required set-asides for the decommissioning of the nuclear plants. Without such set-asides, there may be an incentive for a profit-maximizing firm to plan to declare bankruptcy and abandon a nuclear plant at the end of its useful life, rather than provide for decommissioning over the life of the plant. In this scenario, the public at large would be forced to bear the costs for the decommissioning.

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[107] Tax preferences for “alternative” sources of electricity create a subsidy from all taxpayers to the suppliers of electricity from “alternative” sources.

APPENDIX
Table A-1.--Data on Generation and Use of Electricity in the United States, 1998

Electric Utility Retail Sales By End-Use Sector		Electric Power Generation By Source, 1998			
End User	Million Kilowatthours	Primary Energy Source	Utilities Million Kilowatthours	Non-Utilities Million Kilowatthours	Total Million Kilowatthours
Residential	1,124,004	Coal	1,807,480	64,706	1,872,186
Commercial	948,904	Natural Gas	309,222	222,738	531,960
Industrial	1,047,346	Petroleum	110,158	18,946	129,104
Other	99,868	Nuclear	673,702	0	673,702
		Hydro	304,403	19,738	324,141
		Other	7,205	81,334	88,539

Source: Energy Information Administration, Monthly Energy Review, August, 1999.

Table A-2.--Retail Prices of Electricity Sold By Electric Utilities
(cents per Kilowatthours)

Year	Nominal Price				Real Price			
	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other
1973	2.5	2.4	1.3	2.1	9.18	8.81	4.77	7.71
1974	3.1	3.0	1.7	2.8	10.25	9.92	5.62	9.26
1975	3.5	3.5	2.1	3.1	10.60	10.60	6.36	9.39
1976	3.7	3.7	2.2	3.3	10.79	10.79	6.42	9.62
1977	4.1	4.1	2.5	3.5	11.03	11.03	6.72	9.41
1978	4.3	4.4	2.8	3.6	10.75	11.00	7.00	9.00
1979	4.6	4.7	3.1	4.0	10.33	10.55	6.96	8.98
1980	5.4	5.5	3.7	4.8	10.68	10.88	7.32	9.50
1981	6.2	6.3	4.3	5.3	11.12	11.30	7.71	9.50
1982	6.9	6.9	5.0	5.9	11.65	11.65	8.45	9.97
1983	7.2	7.0	5.0	6.4	11.78	11.46	8.18	10.47
1984	7.15	7.13	4.83	5.90	11.22	11.19	7.58	9.26
1985	7.39	7.27	4.97	6.09	11.19	11.01	7.53	9.23
1986	7.42	7.20	4.93	6.11	11.04	10.71	7.33	9.09
1987	7.45	7.08	4.77	6.21	10.69	10.16	6.84	8.91
1988	7.48	7.04	4.70	6.20	10.31	9.70	6.48	8.54
1989	7.65	7.20	4.72	6.25	10.06	9.46	6.20	8.22
1990	7.83	7.34	4.74	6.40	9.77	9.15	5.91	7.98
1991	8.04	7.53	4.83	6.51	9.62	9.01	5.78	7.79
1992	8.21	7.66	4.83	6.74	9.54	8.90	5.61	7.83
1993	8.32	7.74	4.85	6.88	9.39	8.73	5.47	7.76
1994	8.38	7.73	4.77	6.84	9.22	8.50	5.25	7.52
1995	8.40	7.69	4.66	6.88	8.98	8.22	4.98	7.36
1996	8.39	7.63	4.60	6.72	8.72	7.93	4.78	6.98
1997	8.43	7.59	4.53	6.91	8.56	7.71	4.60	7.02
1998	8.27	7.43	4.50	6.80	8.27	7.43	4.50	6.80

Source: Energy Information Administration Monthly Energy Review, August, 1999, and JCT calculations.